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Canada GDP Growth Annualized

2023 Data - 2024 Forecast - 1961-2022 Historical

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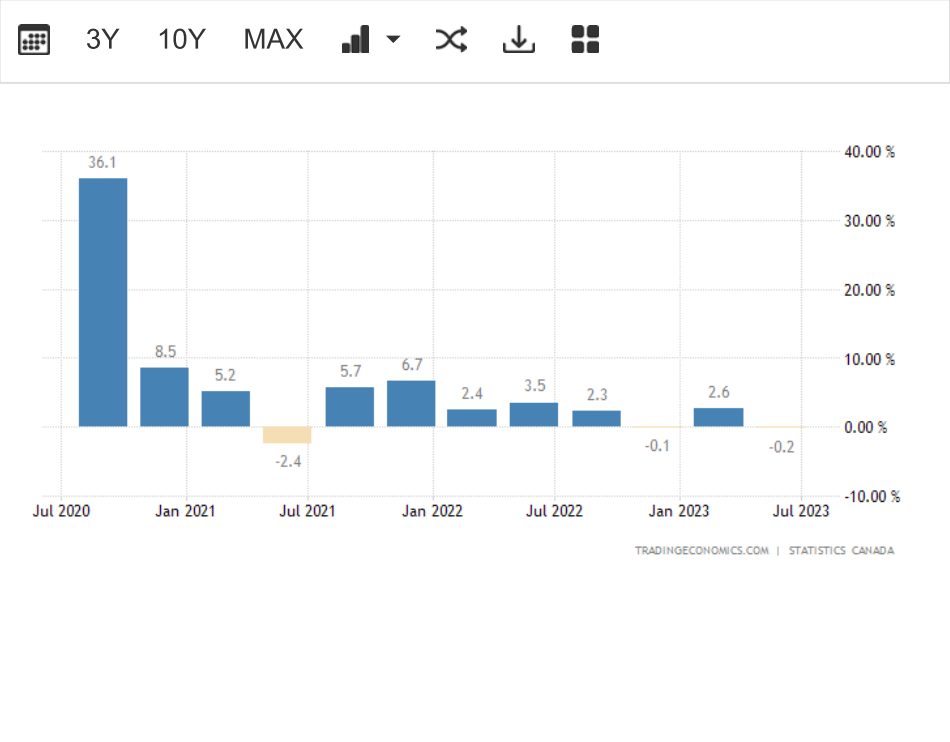
On an annualized basis, the Canadian GDP contracted by 0.2% in June, well below market expectations of a 1.2% expansion, marking the sharpest annualized contraction since the second quarter of 2021. source: Statistics Canada



Calendar	GMT	Reference	Actual	Previous	Consensus	TE
2023-05-31	12:30 PM	Q1	3.1%	-0.1%	2.5%	
2023-09-01	12:30 PM	Q2	-0.2%	2.6%	1.2%	
2023-11-30	01:30 PM	Q3		-0.2%		-

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Canada GDP Growth Annualized

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GDP Annual Growth Rate	1.12	2.08	percent
GDP Constant Prices	2198984.00	2200064.00	CAD Million
Gross National Product	2804048.00	2771304.00	CAD Million
Gross Fixed Capital Formation	449739.00	448400.00	CAD Million
GDP from Utilities	42259.00	42325.00	CAD Million
GDP from Transport	86241.00	86419.00	CAD Million
GDP from Services	1495668.00	1494063.00	CAD Million
GDP from Public Administration	147359.00	146877.00	CAD Million
GDP from Mining	159353.00	156463.00	CAD Million
GDP from Manufacturing	195518.00	198544.00	CAD Million
GDP from Construction	148083.00	148091.00	CAD Million
GDP from Agriculture	40208.00	40803.00	CAD Million

Canada GDP Growth Annualized

GDP Annualized Growth Rate shows the gdp growth that would be registered if the quarter-on-quarter rate of change were maintained for a full year. On the expenditure side, household consumption is the main component of GDP and accounts for 58 percent of its total use, followed by gross fixed capital formation (22 percent) and government expenditure (19 percent). Exports of goods and services account for 32 percent of GDP while imports account for 33 percent, subtracting 1 percent of total GDP. Non-profit institutions serving households' final

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Gross Fixed Capital Formation
Gross National Product
Monthly GDP MoM

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Canada Unemployment Rate

September 2023 Data - 1966-2022 Historical

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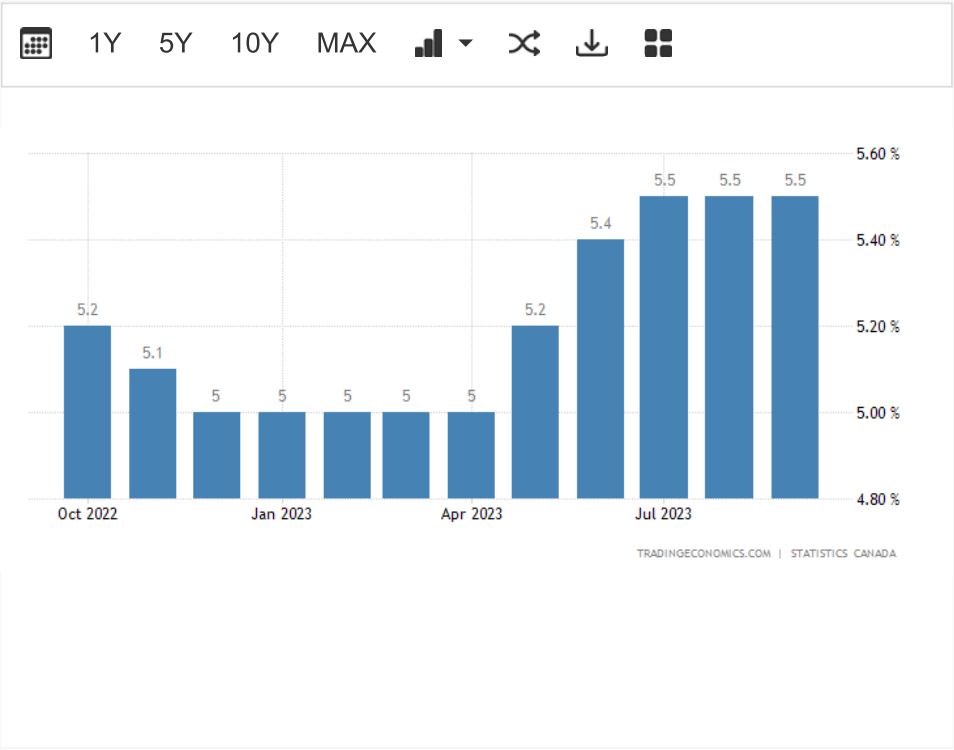
The unemployment rate in Canada remained unchanged for the third consecutive period at 5.5% in August of 2023, slightly missing the estimates of 5.6%. Although the reading pointed to a cooling in the country's labor market since the prior year, the jobless rate stayed well below pre-pandemic averages. Unemployment rose by 8.1 thousand individuals to 1.189 million. Joblessness increased by 0.4% for core-aged men, while staying virtually the same for core-aged woman. Unemployment among youth of both genders was little changed from that in May. Regarding employment, the Canadian economy created a net of 63.8K jobs, well above estimates of a 20 thousand addition. source: Statistics Canada



Calendar	GMT	Reference	Actual	Previous	Consensus	TEF
2023-09-08	12:30 PM	Aug	5.5%	5.5%	5.6%	
2023-10-06	12:30 PM	Sep	5.5%	5.5%	5.6%	

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Canada Unemployment Rate

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Related	Last	Previous	Unit	Refe
Unemployment Rate	5.50	5.50	percent	Sep
Employed Persons	20270.10	20206.30	Thousand	Sep
Unemployed Persons	1189.10	1181.00	Thousand	Sep
Part Time Employment	47.90	7.80	Thousand	Sep
Full Time Employment	15.80	32.20	Thousand	Sep
Employment Change	63.80	39.90	Thousand	Sep
Labor Force Participation Rate	65.60	65.50	percent	Sep
Youth Unemployment Rate	10.50	11.30	percent	Sep
Labour Costs	133.81	131.08	points	Jun
Productivity	105.60	106.25	points	Jun
Wages	29.68	29.72	CAD/Hour	Jul 2
Wages in Manufacturing	30.66	31.14	CAD/Hour	Jul 2
Minimum Wages	16.65	15.55	CAD/Hour	Apr
Population	39.29	38.43	Million	Dec
Average Hourly Earnings	34.98	34.79	CAD	Sep
Employment Rate	62.00	61.90	percent	Sep
Wage Growth	4.30	3.60	percent	Jul 2
Non Farm Payrolls	18069.00	18064.00	Thousand	Jul 2

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Canada Unemployment Rate

In Canada, the unemployment rate measures the number of people actively looking for a job as a percentage of the labour force.

Actual	Previous	Highest	Lowest	Dates	Unit	Frequency	
5.50	5.50	13.70	2.90	1966 - 2023	percent	Monthly	SA

Compare Unemployment Rate by Country

News Stream

Canada Unemployment Rate Steady at 5.5%
The unemployment rate in Canada remained unchanged for the third consecutive period at 5.5% in September of 2023, the highest since January 2022 and slightly missing the estimates of 5.6%. Still, the jobless rate stayed well below pre-pandemic averages. Unemployment rose by 8.1 thousand to 1.189 mil... more
2023-10-06

Canada Unemployment Rate Unchanged at 18-Month High
The unemployment rate in Canada was at 5.5% in August of 2023, remaining unchanged from the 18-month high from the previous month and slightly below market estimates of 5.6%. The data consolidated evidence of some softening in the Canadian labor market since the prior year, but the jobless rate rema... more

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2022 to reflect some softening in the Canadian labor market. Still, the figure remained firmly... more

2023-08-04

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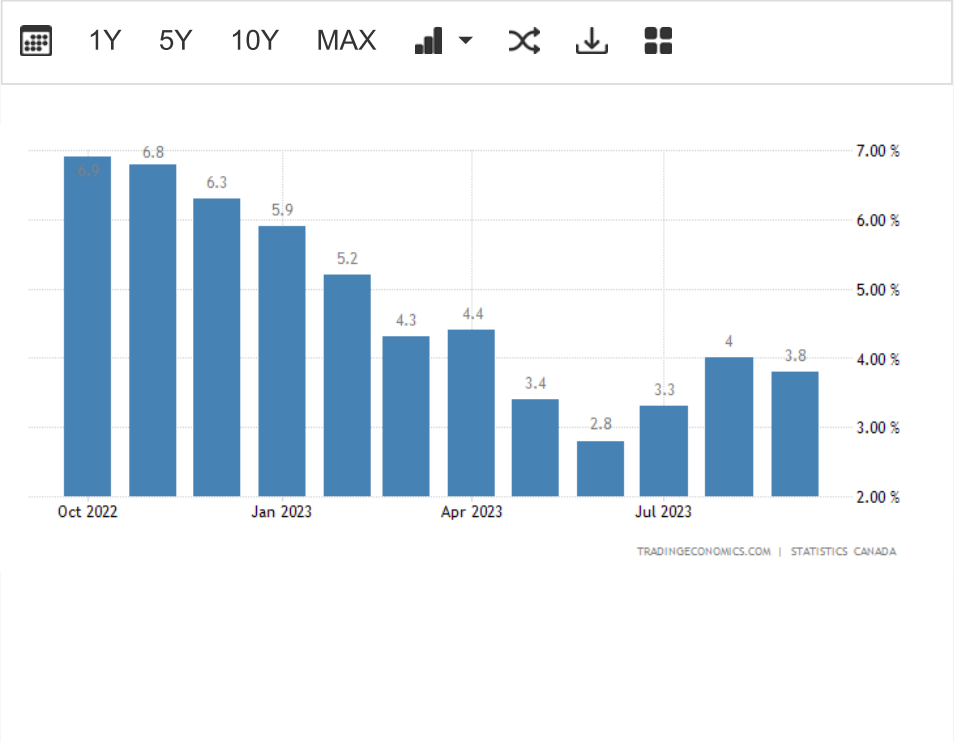
The annual inflation rate in Canada declined to 3.8% in September of 2023 from 4% in the previous month, below market expectations of 4%. The result further strengthened expectations that the Bank of Canada will refrain from further rate hikes in the current cycle, although policymakers heeded the risks of early cuts. Inflation fell for food and beverages (5.9% vs 6.8% in August), largely due to softer price growth for groceries (5.8% vs 6.9%). Additionally, costs slowed for durable goods (0.4% vs 1.4%), amid lower inflation for new passenger vehicles (1.7% vs 3.1%) and deflation for furniture (-4.6%) and household appliances (-2.3%). On the other hand, the sharp increase in crude oil prices over the period drove transportation costs to accelerate (3.2% vs 2.3%), as the surge in gasoline prices (7.5% vs 0.8%) offset the decline in airfare costs (-21.1%). On a monthly basis, the CPI fell by 0.1%, the first reduction of the year. source: Statistics Canada



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Related	Last	Previous	Unit	Reference
Inflation Rate	3.80	4.00	percent	Sep 2023
Inflation Rate MoM	-0.10	0.40	percent	Sep 2023
Consumer Price Index CPI	158.50	158.70	points	Sep 2023
Core Inflation Rate	2.80	3.30	percent	Sep 2023
Core Consumer Prices	153.30	153.40	points	Sep 2023
GDP Deflator	128.50	127.60	points	Jun 2023
Producer Prices	127.00	126.50	points	Sep 2023
Producer Prices Change	0.60	0.00	percent	Sep 2023
Export Prices	143.00	139.10	points	Aug 2023
Import Prices	149.50	146.90	points	Aug 2023
Food Inflation	5.90	6.80	percent	Sep 2023
Wholesale Prices	147.20	142.20	points	Sep 2023
CPI Transportation	171.90	173.60	points	Sep 2023
CPI Housing Utilities	174.80	174.00	points	Sep 2023

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Equipment for 15 percent; Recreation, Education and Reading for 5 percent; Health and Personal Care for 5 percent; Alcoholic Beverages and Tobacco Products for 5 percent and Clothing and Footwear for the remaining 4 percent. The CPI basket is reviewed every four years on the basis of household surveys. The current weights are based on spending patterns in 2002.

Actual	Previous	Highest	Lowest	Dates	Unit	Frequency	
3.80	4.00	21.60	-17.80	1915 - 2023	percent	Monthly	20(

Compare Inflation Rate by Country

News Stream

Canadian Inflation Rate Unexpectedly Falls to 3.8%
The annual inflation rate in Canada declined to 3.8% in September of 2023 from 4% in the previous month, below market expectations of 4%. The result further strengthened expectations that the Bank of Canada will refrain from further rate hikes in the current cycle, although policymakers heeded the r... more
2023-10-17

Canada Inflation Rises More than Expected
The annual inflation rate in Canada rose to 4% in August of 2023 from 3.3% in the previous month, overshooting market expectations of 3.8%. It marked the second consecutive acceleration in Canadian consumer prices since hitting the two-year-low of 2.8% in June, consolidating the return of inflationa... more
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Our Clean Future

A Yukon strategy for climate change, energy and a green economy

Yukon

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ISBN: 978-1-55362-866-8
On the cover: Old Crow solar project. Photo: Government of Yukon/Bree Josie

Caribou near Dempster Highway. Photo: Robert Postma.

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MESSAGE FROM THE PREMIER

Climate change represents the biggest challenge of our generation.

Yukoners have told us loud and clear that they care passionately about climate change and want to see Yukon doing our part. Our government listened.

We have established an ambitious and achievable greenhouse gas reduction target for Yukon and laid out concrete steps we will take to mitigate and adapt to the impacts of climate change. We will integrate these efforts with building a green economy and an energy sector increasingly focussed on renewable sources.

Our Clean Future is the tangible result. We developed shared priorities for climate action in partnership with Yukon First Nations, transboundary Indigenous groups and Yukon municipalities. We heard from the public and members of stakeholder and industry groups. Thank you to all who provided valuable ideas and feedback. This Yukon-made strategy sets clear direction for a strong and resilient future.

Rising to the challenge of climate change requires participation from all Yukoners. Over the past few months, Yukoners have demonstrated what we are willing to do to keep our families, friends and communities safe. In the face of the COVID-19 pandemic, we have had to innovate and adapt in terms of how we connect with loved ones, the ways in which we work and operate businesses, and how we continue to look after one another as a small, closely connected territory.

We are proud of the strength and resiliency demonstrated by Yukoners as we have all adapted to the demands of COVID-19. We call on Yukoners to continue to be leaders as we make further changes to address climate change. As your government, we will be with you every step of the way, from rebates and financial support to help you buy low-carbon technologies to leading by example through improvements to our own buildings and vehicle fleet.

We also look forward to continued collaboration with Yukon First Nations and transboundary Indigenous groups on climate action, as the Council of Yukon First Nations and the Assembly of First Nations-Yukon Region spearhead the development of a Yukon First Nations climate change action plan. We recognize the threat that climate change poses to Indigenous cultures, ways of life and wellbeing and will continue to support Indigenous-led climate action.

As governments around the world tackle the economic impacts of the COVID-19 pandemic, it is critical that economic stimulus efforts align with our climate change commitments. Otherwise, we risk making one challenge worse through our response to another. In partnership with the Government of Canada, we will invest over $200 million over the next four years in renewable energy generation, energy efficiency, clean transportation and adaptation to the impacts of climate change. These actions will position us for long-term sustainability and self-sufficiency while helping Yukoners recover from the financial impacts of the COVID-19 pandemic. Rather than returning to normal, we will take this opportunity to rebuild and refocus for a clean future.

The Honourable Sandy Silver
Premier of Yukon

MESSAGES FROM PARTNERS

Climate change is a threat to the Vuntut Gwitchin, to the lands, water and animals we rely on for sustenance and to practice our culture. Reducing our dependency on fossil fuels though innovative clean energy projects and a green economy that provides sustainable jobs for our youth are opportunities that build community resiliency, energy security and a better future for our children.

Vuntut Gwitchin Government Chief
Dana Tizya-Tramm

White River First Nation is pleased to be a part this initiative to address climate change in the Yukon. Our members are observing changes out on the land and they are happening much quicker than expected. Our community is thrilled to see our 1.5MW solar field constructed in Beaver Creek this summer to offset our use of diesel in the community. By taking action on climate change now, we are lessening the impacts to the land and water that future generations will have to adapt to.

White River First Nation Chief
Angela Demit

Municipal governments have the flexibility not available to larger governments to quickly make changes and find opportunities for climate-change adaptation and mitigation. The City of Dawson is excited to be part of this work and making climate-friendly changes to our own operations.

City of Dawson Mayor
Wayne Potoroka

The City of Whitehorse is aware of the consequences of climate change and the strong political will required to deal with this global challenge. As a result, we declared a climate change emergency on Sept. 23rd, and we continue to closely monitor the risks to our City's residents and businesses. The City is committed to taking action on climate change by working to reduce corporate and community emissions, as well as adopting climate change adaptation initiatives.

City of Whitehorse
Mayor Dan Curtis

As long standing stewards of our traditional territory that spans Yukon, Northwest Territories and British Columbia, Acho Dene Koe First Nation (ADKFN) will continue to support actions and strategies that balance economic opportunity with the preservation of our lands and waters. Through implementation of the strategy, we look forward to working with the Yukon Government and our First Nation partners to maintain our ability to engage in traditional activities and supply more of what we eat through local harvesting and food production.

Acho Dene Koe First Nation Chief
Gene Hope

The Inuvialuit have an interconnected and enduring relationship to the Yukon North Slope. This area and its adjacent seas have supported our culture and sense of identity for a very long time. As such, the preservation of this land and the rest of the Inuvialuit Settlement Region (ISR) is keenly important. We welcome effective partnerships across northern Canada to advance collaborative climate action and sustained traditional livelihoods.

Inuvialuit Regional Corporation Chair and
Chief Executive Officer
Duane Smith

We live in a world that is rapidly changing. Climate change is threatening ecosystems, subsistence harvesting, infrastructure, leisure activities and many other aspects of our lives.

Yukon's population is growing, along with our need for reliable, affordable and renewable energy to continue to power our lives, our work and our economy. New economic opportunities are emerging in the sustainable, green economy.

Across the North, we have a long history of coping with and adapting to changing, and sometimes harsh, conditions. First Nations and Indigenous identities and ways of life are intimately connected with the land, rivers and mountains that are home. Generation after generation, Indigenous people have built and passed along knowledge, skills and values shaped in part by the changing patterns of the landscape.

Our history of adaptation and resilience provides a strong foundation as we work together to address climate change. However, many of the changes we are experiencing now are unprecedented in terms of scope and speed, making it more important than ever to come together to share our collective knowledge and experiences to take action for a healthy future for our children and grandchildren.

In fall 2019, the Government of Yukon declared a climate change emergency, following in the footsteps of the City of Whitehorse and the Vuntut Gwitchin First Nation. In February 2020, Yukon First Nations declared a climate emergency due to the threat that climate change poses to the culture and way of life of First Nations people. In the declaration, Yukon First Nations call on all governments, corporations and individuals to act in the best interests of the planet and future generations as they come together to address climate change.

Outside Yukon, countries around the world have committed through the Paris Agreement to keep global temperature rise below two degrees Celsius and respond to the impacts of climate change. In Canada, the federal government, provinces, territories and communities, are taking action to reduce greenhouse gas emissions and build greener economies powered by clean energy that will be more resilient and sustainable. Yukon will be part of this national and global shift, and we will continue to work collaboratively with governments around the world to take collective action on this global issue.

OVERVIEW OF THE STRATEGY

Mount Decoeli.

The Government of Yukon developed *Our Clean Future* in partnership with Yukon First Nations, transboundary Indigenous groups and Yukon municipalities over the course of three years. Over that time, the partner group gathered four times to establish a vision and values for *Our Clean Future* and to prioritize the areas we should focus on over the next 10 years to respond to the climate emergency. As a result of this collaborative process, the strategy reflects multiple perspectives, worldviews and ideas.

In order to reach each of the objectives that we have set for the next 10 years, all Yukoners need to take part. *Our Clean Future* lays out the specific, tangible actions that the Government of Yukon will take to work toward these objectives. Several Indigenous and municipal partners have also put forward actions they will take to continue to lead the way toward a clean future.

Our Clean Future focuses on the next 10 years until 2030, even though we know that we need to continue to act far past 2030. In fact, our efforts on climate change will need to get more significant as time passes. However, by focusing on the next 10 years, we are holding ourselves accountable to quickly and urgently take the steps that are needed now to begin addressing the climate emergency. This near-term focus can be complemented by a longer-term, multi-generational perspective of climate change often taken by Indigenous people that recognizes how our actions will support environmental stewardship and healthy communities for generations to come.

***Our Clean Future* has been informed by ideas and feedback we received from the public and stakeholders during two rounds of engagement in fall 2018 and 2019. For more information, please refer to the What We Heard reports available on EngageYukon.ca.**

Our vision is to come together as leaders to address climate change by building thriving, resilient communities powered by renewable energy and supported by a sustainable green economy that protects and restores our natural environment.

The steps that we take to achieve our collective vision will be shaped by the following core values established by the Government of Yukon with participating Yukon First Nations, transboundary Indigenous groups and Yukon municipalities:

For all Yukoners

We are building a brighter future for the collective, long-term benefit of all Yukoners today and for those to come, inclusive of ethnicity, culture, language, gender, sexuality, age, ability, education, income and other identity factors.

Empower everyone

We will foster partnerships, collaboration, information-sharing and capacity-building to empower all governments, organizations, businesses and individuals to take action.

Raise awareness

All Yukoners should be aware of climate change, energy and the economy and how they can contribute to building a more sustainable, resilient future.

Be accountable

We will outline specific, measurable and time-bound actions to achieve our collective goals, along with the necessary human and financial resources to implement and monitor them and regular reporting on progress.

Support reconciliation

We will support reconciliation by protecting the unique spiritual relationship that Indigenous people have with the land through strong action on climate change. We will also support self-determination and strengthen relationships between Indigenous and non-Indigenous governments, organizations and individuals through open communication and partnerships.

Respect our natural environment

We will recognize the inherent value and importance of our natural environment and prioritize solutions that protect, conserve and harness natural capital and ecosystem services.

Make informed decisions

We will make informed decisions that respectfully bring together traditional, scientific and local knowledge and Indigenous ways of knowing, doing and being.

No “one size fits all” approach

Our actions will reflect Yukon’s unique strengths and challenges by supporting community-based projects that make sense in their local context.

GOALS

We will work toward four goals that will help us achieve our vision for a clean future:

1. Reduce Yukon's greenhouse gas emissions.

2. Ensure Yukoners have access to reliable, affordable and renewable energy.

3. Adapt to the impacts of climate change.

4. Build a green economy.

Taking action on these four goals will support healthy people, communities and ecosystems. By reducing greenhouse gas emissions and building a green economy that protects and restores the natural environment, we will uphold our joint responsibilities as stewards of the land while supporting sustainable economic wellbeing for future generations. Our actions will also support Yukoners to continue practicing traditional and cultural activities that are being threatened by climate change, supporting physical, mental and spiritual wellbeing.

The following sections describe each goal in more detail and lay out the targets that we will work toward.

The Hart River in winter.

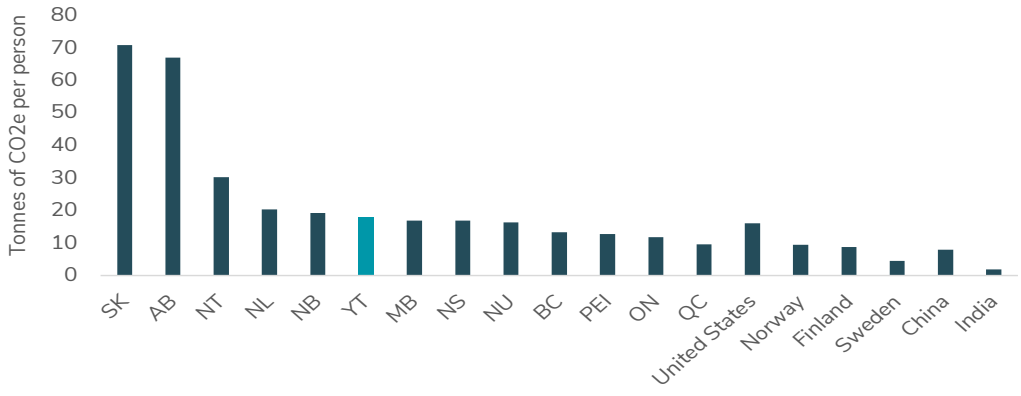
Reducing greenhouse gas emissions

The issue

Climate change is caused by the release of greenhouse gases – like carbon dioxide and methane – primarily from human activities that burn fossil fuels. These activities range from driving vehicles and heating buildings to commercial and industrial processes.

While Yukon's total greenhouse gas emissions are relatively low because of our small population (0.1 per cent of Canada's emissions), our per person emissions of around 18 tonnes per person are the sixth highest in Canada and higher than many other countries. It is important that we do our part to reduce the greenhouse gas emissions that are causing climate change.

Figure 1. Comparison of greenhouse gas emissions per person in Canadian provinces and territories (2017)[1] *and a selection of other countries (2018).*[2]



1 Estimated based on provincial and territorial emissions in Canada's National Inventory Report and population statistics from Statistics Canada.

2 Crippa, M. et al., 2019. Fossil CO2 and GHG emissions of all world countries - 2019 Report. Publications Office of the European Union, Luxembourg, ISBN 978-92-76-11100-9, doi:10.2760/687800, JRC117610.

In Yukon, greenhouse gas emissions mostly come from transportation and heating, with a smaller amount from industry, electricity generation, waste and other areas. Yukon's greenhouse gas emissions are calculated using two main sources of information. The Government of Canada's National Inventory Report, which reports greenhouse gas emissions across the country, is combined with information about fossil fuel sales in Yukon collected by the Yukon Bureau of Statistics to provide the most accurate picture of Yukon's emissions.

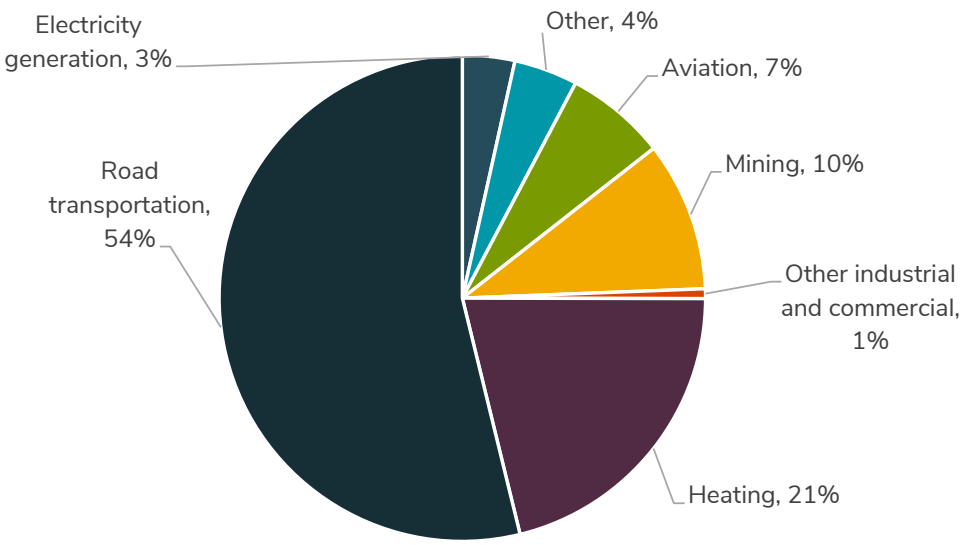


Figure 2. Yukon's sources of greenhouse gas emissions (2017)[3].

Yukon's greenhouse gas emissions only account for emissions that are produced within Yukon's borders. For example, a truck that drives from British Columbia to Yukon to deliver food will produce greenhouse gas emissions in both British Columbia and Yukon. By looking at truck logs that report how many kilometres were driven in Yukon, we can figure out how much of the truck's emissions count toward Yukon's total. Greenhouse gas emissions are tracked and reported on the basis of political borders to avoid double counting when reporting Canadian or global emissions.

3 Government of Yukon, 2020. Greenhouse gas emissions in Yukon.

Our targets

By 2030, we will reduce Yukon's total greenhouse emissions from transportation, heating, electricity generation, other commercial and industrial activities, waste and other areas so that our emissions in these areas are 30 per cent lower than they were in 2010.

This is an ambitious and achievable target that is aligned with Canada's international commitment under the Paris Agreement.

While this greenhouse gas reduction target will ensure we see a decrease in emissions from transportation, heating and other areas, we also need a plan to address greenhouse gas emissions from mining, which were 10 per cent of Yukon's total emissions in 2017.

We will work with industry to set a target for greenhouse gas emissions from placer and quartz mining by the end of 2022 that will see Yukon mines produce fewer emissions of greenhouse gases across their lifecycle for every kilogram or kilotonne of material produced.

This intensity-based target will encourage industry to look for innovative ways to reduce energy use and greenhouse gas emissions from mining, regardless of how many or few mines are in operation at any time.

Reaching these targets by 2030 will put Yukon on the path to net-zero greenhouse gas emissions by 2050 for our entire economy. This long-term target is aligned with the substantial level of greenhouse gas reductions that we know is needed worldwide to avoid catastrophic climate change.

The Yukon-wide greenhouse gas reduction target

Reaching the 30 per cent greenhouse gas reduction target will require extensive modernization to our road transportation and heating systems, which together contribute 75 per cent of Yukon's emissions. It will also require significant diversified investments in more renewable electricity generation, creating local jobs and economic opportunities. By reaching this target, we will inspire others by demonstrating that a remote, northern jurisdiction can achieve a significant reduction in greenhouse gas emissions.

We have learned several lessons since the last time greenhouse gas reduction targets were set for Yukon. In the 2012 Climate Change Action Plan Progress Report, twelve different targets were set for a variety of sectors. While the targets related to greenhouse gas emissions from buildings and electricity generation were met, the other targets were not met or could not be reported on due to a lack of available data.

Since that time, we have made improvements to how we gather and report greenhouse gas emissions data. We are now setting targets that we know we can track through available data. We have also conducted modelling work to help us set a greenhouse gas reduction target that is both ambitious and achievable.

Mining plays a central role in the transition to a green economy. Minerals are vital to low carbon technologies – from batteries to wind turbines, solar panels and electric vehicles. Meeting an emissions intensity target will help Yukon's mining industry sustainably produce the materials needed for the global green economy.

Greenhouse gas reduction modelling

In 2017, the most recent year we have data for, Yukon's greenhouse gas emissions, with the exception of mining, were 624 kilotonnes. This is an increase from 2010 emissions of 592 kilotonnes. Based on modelling, we anticipate that Yukon's emissions, excluding mining emissions, could increase to 678 kilotonnes in 2030 if we do not take action. As a result, to reach our 30 per cent greenhouse gas reduction target by 2030, we estimate that we need to reduce our emissions by 263 kilotonnes.

However, forecasting what Yukon's greenhouse gas emissions could be in 2030 is very challenging. Future emissions depend on several factors, including population growth, the economy, and the success of the actions in this strategy, all of which are hard to predict. This makes it very important to track actual greenhouse gas emissions on a regular basis and be flexible and adaptive in our efforts.

Assuming that we need to reduce greenhouse gas emissions by 263 kilotonnes, we expect that the actions outlined in this strategy will get us three-quarters of the way there. To close this gap, we will update our actions in 2024 based on our progress and new information that has emerged. In 2027, we will complete another update based on the newest information on our progress. As part of tracking our progress, we will expect to see Yukon's greenhouse gas emissions go down to at least 10 per cent below 2010 levels by 2025 in order to reach the 2030 target.

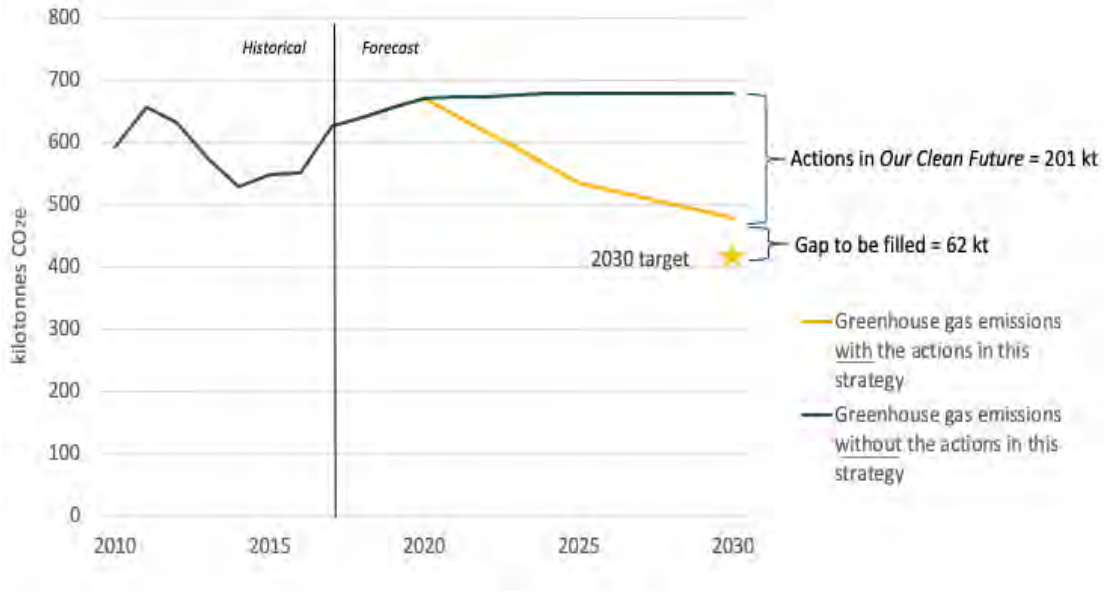


Figure 3. Historical and forecasted non-mining greenhouse gas emissions with and without the actions identified in this strategy.

Anticipated greenhouse gas reductions in 2030 in kilotonnes (kt)

Increasing the use of zero emission vehicles: • Requirements for zero emission vehicles to be 10 per cent of light-duty vehicles sales by 2025 and 30 per cent by 2030. • Rebates for purchasing zero emission vehicles. • Commitment for half of all new cars purchased by the Government of Yukon to be zero emission vehicles.	13 kt
Increasing the use of public and active transportation.	6 kt
Using cleaner fuels for transportation: • Requirement for diesel fuel to be blended with with biodiesel or renewable diesel beginning in 2025. • Requirement for gasoline to be blended with ethanol beginning in 2025.	59 kt 11 kt
Making buildings more energy efficient and switching to renewable heat: • Funding, rebates and low-interest financing for retrofits. • Requiring new buildings to be significantly more energy efficient.	12 kt 5 kt
Conducting energy efficiency retrofits and installing renewable heating systems in Government of Yukon buildings.	8 kt
Using clean electricity: • Requiring 93 per cent of the electricity on the main Yukon grid to come from renewable sources on average. • Reducing the use of fossil fuels for electricity generation in off-grid communities by 30 per cent through community-based renewable energy projects. • Substituting some of the diesel used to generate electricity with clean diesel alternatives like renewable diesel or biodiesel.	79 kt 10 kt 4 kt
Total*	**201 kt**
GHG reduction needed to reach 30 per cent target	**263 kt**

*The total does not match the sum of the invidual policies because of policy interactions where two or more policies contribute to the same greenhouse gas reduction.

The mining intensity target

From 2009 to 2017 – the period of time for which we have reliable greenhouse gas emissions data for Yukon – emissions from placer and quartz mining have varied from year-to-year depending on the amount of mining activity in the territory. These annual fluctuations can be seen in Yukon's total greenhouse gas emissions as well, which is the direct outcome of increases or decreases to mining emissions as well as the indirect impact that mining activity has on overall economic activity in the territory. Overall, mining emissions have ranged from 10 to 15 per cent of Yukon's total emissions over this period.

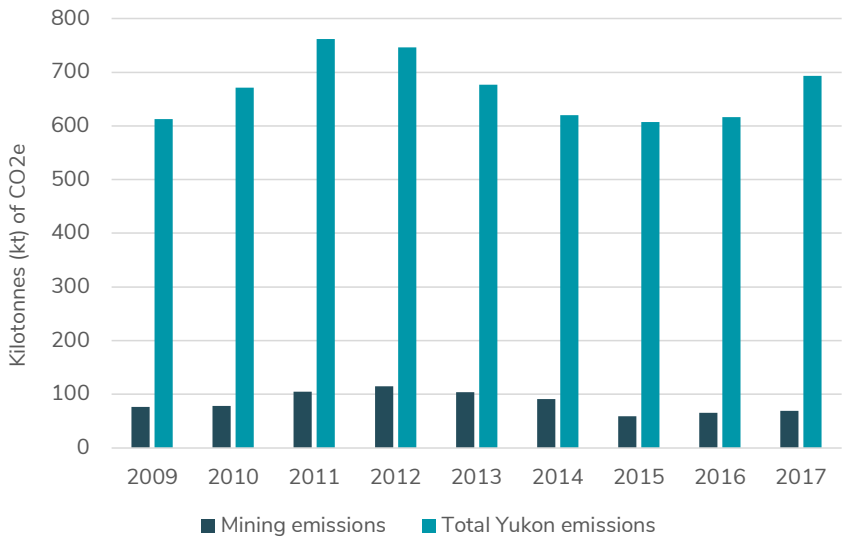


Figure 4. Yukon's total greenhouse gas emissions and the portion of emissions from mining from 2009 to 2017.[4]

The year-to-year variability of Yukon's mining emissions makes it difficult to set a maximum level of greenhouse gas emissions from mining to be reached by a certain date. If mining activity were to decrease, total mining emissions could reach the target without requiring any improvements to how mines operate. If mining activity were to increase, the target could become unachievable.

Unlike an absolute greenhouse gas reduction target, an intensity-based target that establishes a desired level of greenhouse gas emissions per unit of material produced will encourage operational efficiencies regardless of how many or how few mines are in operation at any one time.

In addition, establishing a tailored approach for mining emissions eliminates the possibility for a substantial change in mining activity to skew our efforts to reduce emissions from other parts of Yukon's economy. For example, if mining emissions were part of the Yukon-wide greenhouse gas reduction target, a significant decrease in mining activity could help us to reach the 2030 target without needing to make as many improvements to our transportation and heating systems.

4 Government of Yukon, 2020. Greenhouse gas emissions in Yukon.

Caribou herd.

While a tailored intensity-based approach to mining emissions makes sense for the reasons noted above, it is important to set up a system that works. The Government of Yukon will work with industry to set the mining intensity target, or targets, for placer and quartz mining by 2022. During that time, we will consider challenges like the different types of mining operations in Yukon, how to accurately track placer gold production and how to account for greenhouse gas emissions across the entire mine lifecycle from development through to closure and remediation. These are challenging issues that will take time to think through. We will also assess whether the current actions in *Our Clean Future* are sufficient to reach the target that is set, or whether additional actions need to be taken.

As we do this work, we will keep in mind the intensity-based targets for mining in Canada's Output-Based Pricing System. The Output-Based Pricing System is designed to encourage industrial emitters to innovate and reduce their greenhouse gas emissions while maintaining competitiveness and protecting against carbon leakage. Quartz mines in Yukon may be part of Canada's Output-Based Pricing System depending on their size, which is why it will be important for both intensity-based approaches to be coordinated.

When designing climate policy, it is important to avoid unintentionally creating carbon leakage. Carbon leakage occurs when companies or industries shift their operations to other parts of the world that have less stringent climate policies. The result of carbon leakage is that global greenhouse gas emissions may not go down, or may even increase, depending on the situation.

Power lines running along highway.

Ensuring reliable, affordable and renewable energy

Electricity

The issue

In Yukon, historically we have met over 90 per cent of our electricity needs each year with clean, renewable power because of our large supply of hydroelectricity.[5] As Yukon's economy and communities grow, and as Yukoners increasingly invest in electric vehicles and electric heating technologies, demand for electricity will grow.

All but four of Yukon's communities are connected to the same electrical transmission network, referred to as the Yukon Integrated System or the main electricity grid. Most of the generation and high voltage transmission of electricity on the main grid is managed by the Yukon Energy Corporation, while most distribution is the responsibility of ATCO Electric Yukon. The four communities not connected to the main electricity grid – Beaver Creek, Burwash Landing/Destruction Bay, Watson Lake and Old Crow – are served by four micro-grids that have been primarily powered by diesel generators operated by ATCO Electric Yukon.

5 As demonstrated by annual submissions to the Yukon Utilities Board by the Yukon Energy Corporation and ATCO Electric Yukon.

Figure 5. Yukon's electrical generation facilities and transmission lines. Figure provided by the Yukon Energy Corporation.

Our targets

For Yukon's main electricity grid, we will aspire to see 97 per cent of the electricity we use come from renewable sources by 2030.

This includes electricity used by mines that are connected to the grid. This target is consistent with the bold vision in the Yukon Energy Corporation's 10-year renewable electricity plan, released in draft form in January 2020.

For the communities that are not connected to the main electricity grid, we will reduce diesel use for electricity generation by 30 per cent by 2030, compared to 2010.

We will also substitute some of the diesel fuel that continues to be used with clean alternatives like biodiesel and renewable diesel.

To make sure the lights turn on when we need them and that we are able to heat our homes – even on the coldest days of winter – we will also have the necessary backup power on hand. Today, fossil fuels like diesel and natural gas are best suited for backup power because they are quick and reliable. Over time, technological improvements and efforts to be more energy efficient will reduce the amount of fossil fuels we need to have as backup energy.

How we will meet them

To meet Yukon's renewable electricity targets, we need to invest in more electricity generation capacity, which could range from wind and solar to hydroelectricity projects.

For the main Yukon grid, the Government of Yukon will set a minimum regulatory requirement for the Yukon Energy Corporation to generate at least 93 per cent of electricity from renewable sources on average. It will then be up to the Yukon Energy Corporation to determine the best way to meet or exceed this target.

For off-grid communities, the Government of Yukon will continue to work in partnership with Yukon First Nations, communities and ATCO Electric Yukon to establish community-based renewable electricity projects in order to reduce diesel use for electricity generation by 30 per cent by 2030. Efforts to substitute some of the diesel that continues to be used for electricity generation with clean diesel alternatives like biodiesel and renewable diesel will help us reduce greenhouse gas emissions even further.

Investments in new renewable electricity generation will create local jobs and opportunities, but electricity rates may increase. This is in part because significant capital investments will be needed. It is also because the full costs of using and relying on diesel and other fossil fuels – like air pollution, greenhouse gas emissions and fuel spills – are not reflected in the fees we currently pay for these energy sources.

The Government of Yukon will strive to minimize the impact of any electricity rate increases on Yukoners by helping individuals, families and businesses use energy more efficiently. We will also work with Yukon's electrical utilities to facilitate energy-efficient practices and reduce demand at peak times. This will reduce the amount of new electricity generation infrastructure that needs to be built and the related impacts on electricity rates.

The Yukon Energy Corporation released a draft version of its 10-year renewable electricity plan, "Electricity for 2030," in January 2020. The plan identifies the electricity generation and storage projects that are needed to exceed the 93 per cent regulatory requirement that will be established under *Our Clean Future*. The Yukon Energy Corportion expects that its plan will result in 97 per cent renewable electricity on the main grid on average by 2030. For more information, visit yukonenergy.ca.

Dempster Highway. Photo: Fritz Mueller.

Transportation and heating

The issue

Two-thirds of the energy we use for transportation and heating comes from fossil fuels. Over the next 10 years, we need to reduce our reliance on fossil fuels in these areas.

Our targets

By 2030, we will meet 50 per cent of our heating needs with renewable energy sources. For transportation, we expect to see emissions from road transportation go down by at least 30 per cent by 2030, compared to 2010, to reach the overall greenhouse gas reduction target for Yukon.

How we will meet them

We will meet these targets through efficiency improvements to reduce energy demand, switching to clean electricity for some of our transportation and heating needs, developing local renewable heat sources like wood energy, and using cleaner transportation fuels.

Adapting to climate change

The issue

We are already experiencing significant changes to our climate. Since 1948, temperatures in northern Canada have increased by 2.3 degrees Celsius, with temperature rise being most rapid in Yukon and the Northwest Territories[6]. This is close to three times the rate at which global temperatures are rising. Over the same period, rain and snowfall increased by six per cent in Yukon and has become more unpredictable[7].

Some climate change impacts we have experienced, and will continue to experience, are:

- Permafrost thaw, which is damaging buildings and roads, changing landscapes and affecting ecosystems;
- Changes to weather and conditions on the land, which are reducing access to country foods, deepening food security concerns, and impacting health and cultural identities;
- More frequent extreme weather events, which can destroy habitats and homes and cause flooding;
- More severe forest fires, which pose a risk to communities and affect ecosystems and wildlife; and
- Glacier melt, which is affecting river flow patterns, water temperatures and aquatic health.

Adapting to climate change involves making informed, forward-looking decisions to minimize the negative impacts that climate change may have on our health, wellbeing, ways of life, and livelihoods while also taking advantage of new opportunities that may arise. In Yukon, effective adaptation will save lives, support healthy ecosystems, minimize damage to buildings and infrastructure, and protect Indigenous cultures and ways of life.

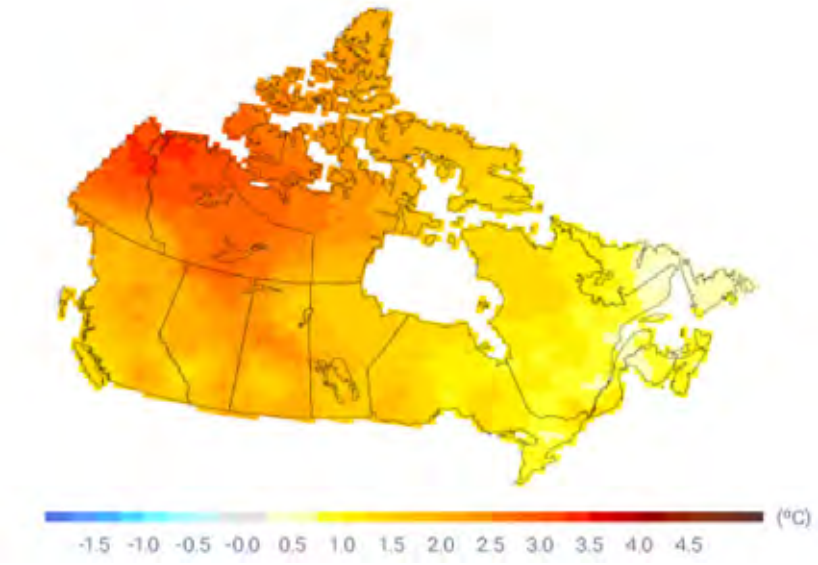


Figure 6. Change in annual temperature across Canada from 1948 to 2016. Figure from Canada's Changing Climate Report.

6 Government of Canada, 2019. Canada's Changing Climate Report.
7 Streicker, J., 2016. Yukon Climate Change Indicators and Key Findings 2015. Northern Climate ExChange, Yukon Research Centre.

Our target

By taking action to adapt to climate change, including impacts we are already experiencing and those yet to come, we will make sure that Yukon is highly resilient to the impacts of climate change by 2030.

To track progress toward this target, the Government of Yukon will work with Indigenous and municipal partners to assess how exposed Yukoners are to climate impacts, and how climate change will impact people and communities in different ways. We will also assess the ability of our built, natural and social systems to moderate potential damages, take advantage of opportunities, and cope with the consequences of climate change in the territory. Things we may track as part of this work could be the number of communities that have prepared climate change adaptation plans or the number of Yukoners that are living in high-risk areas.

Our work with Indigenous and municipal partners will also inform a common understanding of what it means to be climate resilient, as well as the ways in which communities are already resilent because of strong community connections, an intimate understanding of the land, or other sources of strength.

How we will meet it

We will increase Yukon's resiliency to climate change by taking action to reduce our exposure to climate hazards like wildfires and flooding, decrease how sensitive we are to those hazards, and increase our capacity to adapt. Our actions will be informed by Indigenous, local and scientific knowledge and ways of knowing, doing and being. Our efforts will touch on infrastructure, housing, land use planning, emergency preparedness, ecosystem health, food security, and health and wellbeing in recognition of how broadly climate change can affect our lives. We will work with partners across Yukon to share information, build capacity to understand and respond to climate change impacts, and plan for the future.

When planning for the climatic changes we expect to see, it is important to recognize that there is a range of possible climate impacts depending on global greenhouse gas emissions. In order to make sure we are planning conservatively, we will assume that global greenhouse gas emissions will continue along their current path when forecasting how Yukon's climate will change. Right now, global greenhouse gas emissions are most consistent with the Intergovernmental Panel on Climate Change's RCP8.5 pathway, which projects 2.6 to 4.8 degrees of warming globally by the end of the century. Even if we do not experience this level of warming, Yukoners will benefit from the investments in people and communities that climate change adaptation involves.

A risk-based and human-centered approach

Not all individuals, households or communities will be affected in the same way by the changes that are coming. Our ability to adjust to changing conditions, reduce potential damages and take advantage of new opportunities differs from person to person and community to community. For example, resilience

Carcross Commons opening.

to climate change is affected by the condition of our homes, whether we rent or own, our ability to afford insurance, the health conditions we live with, and the presence of friends, family and community to support us and provide comfort during difficult times. As a result, climate change can amplify socioeconomic stresses that individuals, households and communities are already facing.

In *Our Clean Future*, our approach to adaptation recognizes the importance of reducing the risks we all face while also working to alleviate the conditions that can make people more vulnerable to climate change. This includes working to improve human health, food security and housing to enhance the resilience of Yukoners and Yukon communities.

Fireweed Market.

Building a green economy

The issue

A green economy creates economic prosperity while protecting and restoring the natural environment in order to build a healthy, prosperous future for generations to come. In a green economy, energy and other resources are used efficiently, with minimal waste. Economic activities and operations release fewer carbon dioxide and other greenhouse gas emissions. A green economy is also resilient and inclusive so that communities, businesses and individuals can adapt to the impacts of climate change and take advantage of new opportunities.

There are many opportunities for Yukoners as we build a green economy in the territory alongside national and international efforts. As local, national and global demand for green goods and services increases, there are opportunities for Yukon innovators, entrepreneurs and businesses to supply clean energy and find ways to use energy more efficiently. The knowledge economy will grow as Yukoners come up with innovative solutions to local and global challenges. Efforts to use energy and other resources more efficiently will also reduce operating costs for Yukon businesses.

What we will do

Yukon's approach to a green economy focuses on:

- Helping Yukon businesses, individuals and communities plan for, and benefit from, the economic opportunities that will arise as we take action on climate change and energy;
- Supporting innovation and the knowledge economy and recognizing the achievements of local green businesses and organizations; and
- Making it easier for businesses, communities and entrepreneurs to access funding and support for green projects across Yukon.

Building a green economy will help Yukoners take care of the natural environment so it can support long-term jobs and economic activity, as well as continued traditional and cultural activities and strong mental and physical wellbeing. A green economy recognizes principles upheld by Indigenous people for millenia that people must respect and take care of the land so that the land can take care of us.

Tracking progress

We will track our progress toward building a green economy by looking at changes to greenhouse gas emissions per person and greenhouse gas emissions per unit of real gross domestic product over time. These indicators will tell us whether Yukon's economy is becoming more efficient in terms of the greenhouse gas emissions we generate relative to the number of people living in the territory and the size of our economy.

Carbon pricing

A price on carbon pollution is one way that the Government of Canada is stimulating the green economy. The Government of Canada's carbon levy encourages individuals and businesses to invest in low-carbon alternatives and fosters innovation.

The Government of Yukon's carbon rebate returns carbon pricing revenues from the Government of Canada to Yukon individuals, businesses, First Nations and municipalities. The Government of Yukon's carbon rebate upholds the principles of the Pan-Canadian Framework on Clean Growth and Climate Change while protecting vulnerable families, and ensuring the territory remains competitive as we transition to a green economy. For businesses, Yukon's carbon rebate includes a super green credit to encourage future investments in renewable energy generation and energy efficiency.

Kaskawulsh Glacier.

Taking action

Our Clean Future: is organized into seven areas:

Transportation

Homes and buildings

Energy production

People and the environment

Communities

Innovation

Leadership

Within each area, there are several objectives that we will work toward over the next 10 years that reflect the priorities of the Government of Yukon and participating municipal and Indigenous partners.

Each objective contributes to one or more of these four goals:

Reducing greenhouse gas emissions;

Ensuring Yukoners have access to reliable, affordable and renewable energy;

Adapting to the impacts of climate change; and

Building a green economy.

Actions

To reach each objective, we need to take specific, tangible actions. The Government of Yukon's actions in this strategy lead by example through major improvements to government vehicles and buildings while also supporting Indigenous governments and organizations, municipalities, businesses and individuals to take collaborative action to build a strong, healthy future.

The actions in *Our Clean Future* are the Government of Yukon's top priorities for addressing climate change, meeting energy needs and building a green economy over the next 10 years. For each action, the Government of Yukon department or agency responsible for leading the implementation of that action is listed for transparency and accountability. In many cases, other departments will be involved as well.

In addition to the Government of Yukon's actions, Indigenous and municipal partners have been invited to identify actions they will take to work toward our collective objectives set out in *Our Clean Future*. Several partner actions are included in this version of *Our Clean Future* and the door remains open for partners to identify additional actions in the future.

Timing

The Government of Yukon's actions will be updated every three to four years. This will ensure the strategy remains relevant from now until 2030 and that we remain up-to-date on best practices and new developments.

Funding

To implement many of the Government of Yukon's actions in this strategy, we will continue to depend on partnerships with the federal government. In particular, we hope to receive continued federal support for investments in clean transportation, building energy efficiency, renewable energy projects, emergency preparedness and response, and community adaptation.

In partnership with the federal government, the Government of Yukon plans to spend over $500 million over the next 10 years to implement *Our Clean Future*. This investment will put Yukon on the path to significantly reduce our greenhouse gas emissions from transportation, heating, electricity generation and other areas, prepare our communities for ongoing climate change, and enable all Yukoners to participate in these efforts by providing necessary financial and technical support.

Over $400 million of this investment will directly support economic development and recovery by investing in local renewable energy, infrastructure and building projects, encouraging purchases of green technologies like zero emission vehicles, and supporting Yukon businesses and workers to develop new skills for the green economy.

Government of Yukon departments and agencies

CS: Community Services
EcDev: Economic Development
EDU: Education
EMR: Energy, Mines and Resources
ENV: Environment
ECO: Executive Council Office
FIN: Finance
HSS: Health and Social Services
HPW: Highways and Public Works
JUS: Justice
PSC: Public Service Commission
TC: Tourism and Culture
YDC: Yukon Development Corporation
YEC: Yukon Energy Corporation
YHC: Yukon Housing Corporation

Tr'ondëk Hwëch'in Farm.

Working together

Community leadership and successful partnerships are key to addressing climate change. In Yukon, many impactful climate change and energy projects have been driven by community champions and supported by collaborative partnerships between governments, organizations, businesses and individuals. These projects range from the Old Crow solar project, Kluane wind project and solar panels in Mayo to the Tr'ondëk Hwëch'in First Nation and Carcross-Tagish First Nation community farms. Moving forward, Indigenous governments and organizations, municipalities, businesses, organizations, individuals, youth and Elders will all continue to play key roles building a clean future for Yukon.

Indigenous and municipal leadership

The objectives set out in each of the seven areas of *Our Clean Future* were identified as priorities for Yukon by the Government of Yukon and participating Yukon First Nations, transboundary Indigenous groups and Yukon municipalities. Several Indigenous and municipal partners have put forward ambitious actions they will take to work toward the objectives that are particularly relevant to their communities, complementing and building on the Government of Yukon's efforts in those areas and demonstrating continued community leadership.

In addition to the actions highlighted below, the Council of Yukon First Nations and the Assembly of First Nations-Yukon Region are leading the development of a Yukon First Nations climate change vision and action plan that will complement *Our Clean Future* by providing a First Nations-led perspective on climate action in Yukon.

Indigenous- and municipal-led actions by area

Purchase an electric or hybrid vehicle and install an electric vehicle charging station in Mayo.	Village of Mayo
Implement challenge-based campaigns to encourage behavioral shifts on walking and active transportation, as well as on topics such as vehicle use, energy use, and waste.	City of Dawson
Develop a program and educational campaign for reducing winter idling.	City of Dawson
Retrofit the Village of Mayo Community Centre to be more energy efficient based on an energy assessment completed for the facility.	Village of Mayo
Explore opportunities to replace diesel heat in Old Crow with fast-growing, locally harvested willow distributed through a district heat system.	Vuntut Gwitchin Government
Implement a water metering and bleeder reduction program.	City of Dawson
Partner with the University of Saskatchewan to improve and develop more comprehensive energy audits in the Gwich'in communities.	Gwich'in Tribal Council
Develop an energy action plan for the Inuvialuit Settlement Region by 2021.	Inuvialuit Regional Corporation.
Build a 1.5 megawatt (MW) solar farm in Beaver Creek that will displace up to 60 per cent of the diesel used for electricity generation in the community.	White River First Nation
Build a solar farm in Old Crow that will meet 24 per cent of Old Crow's electricity demand and enable the diesel generators to be turned off for 2,200 hours each year.	Vuntut Gwitchin Government
Set up a wind measurement tower in summer 2020 to investigate the potential for a wind energy project to meet Old Crow's electricity demand in the winter months.	Vuntut Gwitchin Government
Work with partner organizations to convert the Gwich'in Camp from full reliance on diesel power to hybridized renewable energy sources.	Gwich'in Tribal Council
Continue to heat the Village of Mayo swimming pool using solar energy.	Village of Mayo
Work with Polar Knowledge Canada to createand mobilize knowledge of sustainable energy, food sovereignty and revitalization and promotion of Indigenous Traditional Knowledge.	Gwich'in Tribal Council

Create municipal incentives for green buildings, businesses, and business practices.	City of Dawson
Develop a climate change strategy for the Inuvialuit Settlement Region by 2021.	Inuvialuit Regional Corporation
Conduct urban fire smarting.	Village of Haines Junction
Develop a Community Energy and Implementation Plan for Old Crow that will identify activities to reduce reliance on fossil fuels and achieve the 2019 Vuntut Gwitchin First Nation General Assembly resolution to reach carbon neutrality by 2030.	Vuntut Gwitchin Government
Create a reserve fund for projects related to climate change, energy, and green economy, and fund it from the municipal carbon tax rebate.	City of Dawson
Set improved service standards with respect to waste pickup, plowing, and bleeders.	City of Dawson
Explore and implement a comprehensive composting program to encourage and/or incentivize increased diversion of food waste.	City of Dawson
With support from Gender Equality Canada, work with women artisans in Beaufort Delta communities to address the systemic gaps that are hindering their business's opportunities.	Gwich'in Tribal Council
Continue looking for partnerships to build innovative technical solutions to decrease the diesel dependency in the Gwich'in Settlement Area.	Gwich'in Tribal Council
Create an Energy and Sustainability Analyst position by 2020 to help build the Council of Yukon First Nations' capacity to assist Yukon First Nations in the pursuit of projects, programs and policies that support renewable energy and reduce greenhouse gas emissions as well as provide guidance and visioning on the creation of a Yukon First Nations Climate Strategy and help strengthen Yukon First Nations energy literacy and capacity overall.	Council of Yukon First Nations
Develop a policy for municipal operations and events, including with respect to resource use, waste, and energy efficiency.	City of Dawson
Continue to run the Climate Future Exchange program to connect northern youth to their counterparts from other regions and enable them to create community-based projects that use Indigenous knowledge to reduce carbon footprint in the Gwich'in Settlement Area.	Gwich'in Tribal Council
Continue to host energy and climate change terminology workshops.	Inuvialuit Regional Corporation

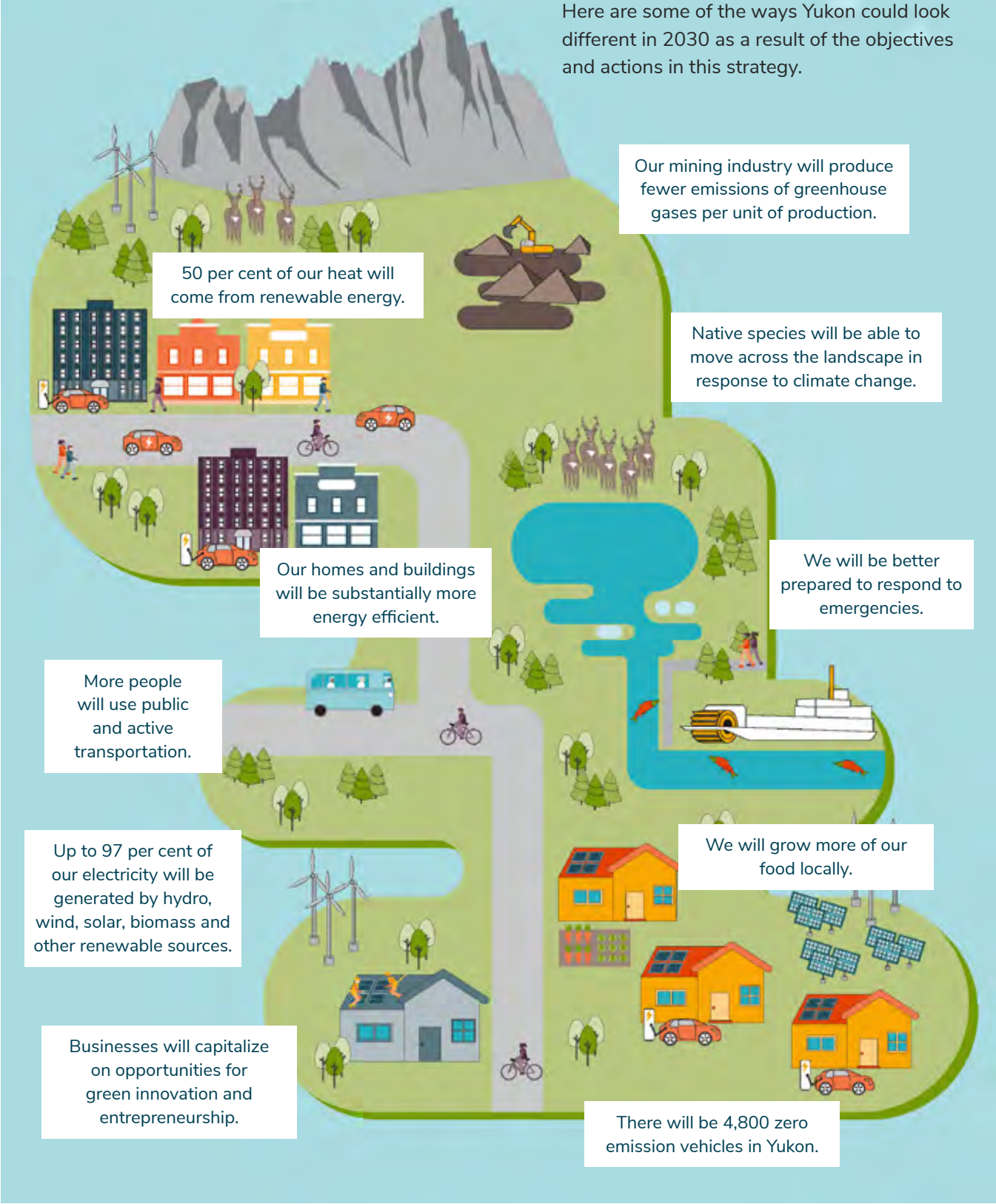
Indigenous and municipal partners will continue to be able to put forward actions they will take to support a clean future through the online version of this strategy.

Individuals, businesses and organizations

Our Clean Future also creates many opportunities for individuals, businesses and organizations to take part in reducing emissions, enhancing energy security, making Yukon more resilient, and building a green economy through financial support, information and advice. Here are some of the ways you can participate and help ensure we are able to build the clean, resilient Yukon we want for the future.

Yukon in 2030

Here are some of the ways Yukon could look different in 2030 as a result of the objectives and actions in this strategy.



Area #1: Transportation

Currently, almost all the energy we use to meet transportation needs comes from fossil fuels. As a result, transportation by road and air is the largest source of greenhouse gas emissions in Yukon, contributing 61 per cent of total emissions.[8] Close to 90 per cent of transportation emissions come from road transportation, with a relatively equal split between personal vehicles and commercial and industrial vehicles, including those that transport food, fuel and other products. The remaining transportation emissions are from aviation.

Our approach to transportation will make it easier for Yukoners to use clean forms of transportation, reducing fuel costs for individuals, families and businesses as well as greenhouse gas emissions. We will respond to the impacts of climate change on our transportation systems to ensure Yukon's economy remains strong and resilient. Our transportation objectives are supported by efforts in other areas of this strategy that will reduce our dependence on imported fossil fuels and other products by supporting local goods and services.

Transportation objectives at a glance

CO₂ $	Increase the number of zero emission vehicles on our roads.
CO₂	Reduce the lifecycle carbon intensity of transportation fuels.
CO₂ ⚡ $	Increase the use of public and active transportation.
CO₂ ⚡	Reduce the carbon footprint from medium and heavy-duty vehicles.
CO₂ ⚡ $	Be more efficient in how and when we travel.
🌡 $	Ensure roads, runways and other transportation infrastructure are resilient to the impacts of climate change.

8 Government of Yukon, 2020. Greenhouse gas emissions in Yukon.

Increase the number of zero emission vehicles on our roads.

Increasing the use of electric vehicles and other vehicles with low or zero greenhouse gas emissions is one of the most significant ways we can reduce emissions. There are already several electric vehicles in Yukon, and they are a reliable and affordable transportation solution, even in our cold climate. Supporting a broader transition to zero emission vehicles will allow Yukoners to continue to go where and when they need to while reducing greenhouse gas emissions, improving air quality, and supporting local dealerships. While electric vehicles have been shown to have lower lifecycle greenhouse gas emissions than fossil fuel vehicles[9], Yukon will support efforts to address other social and environmental concerns with electric vehicle supply chains and to continue reducing the lifecycle emissions of electric vehicles.

Our target for 2030 is to have at least 4,800 zero emission vehicles registered in the territory – or approximately one in every eight passenger vehicles on the road. Our commitment to meet at least 93 per cent of Yukon's electricity needs from renewable sources, on average, while aiming for 97 per cent, will ensure these vehicles are powered sustainably.

ACTIONS

T1.	Work with local vehicle dealerships and manufacturers to establish a system by 2024 to ensure zero emission vehicles are 10 per cent of light duty vehicle sales by 2025 and 30 per cent by 2030.	EMR
T2.	Ensure at least 50 per cent of all new light-duty cars purchased by the Government of Yukon are zero emission vehicles each year from 2020 to 2030.	HPW
T3.	Provide a rebate to Yukon businesses and individuals who purchase eligible zero emission vehicles beginning in 2020.	EMR
T4.	Continue to install fast-charging stations across Yukon to make it possible to travel between all road-accessible Yukon communities by 2027 and work with neighbouring governments and organizations to explore options to connect Yukon with BC, NWT and Alaska.	EMR
T5.	Provide rebates to support the installation of smart electric vehicle charging stations at residential, commercial and institutional buildings in collaboration with Yukon's public utilities beginning in 2020.	EMR
T6.	Require new residential buildings to be built with the electrical infrastructure to support Level 2 electric vehicle charging beginning on April 1, 2021.	CS
T7.	Draft legislation by 2024 that will enable private businesses and Yukon's public utilities to sell electricity for the purpose of electric vehicle charging.	EMR
T8.	Continue to run public education events and campaigns to raise awareness of the benefits of electric vehicles and how they function in cold climates.	EMR

Reduce the lifecycle carbon intensity of transportation fuels.

Even with more zero emission vehicles on the roads and more people walking, cycling or taking the bus, liquid fossil fuels like gasoline and diesel are expected to be the main source of energy for transportation in Yukon over the next 10 years. As a result, a key way to reduce greenhouse gas emissions from transportation in the near term is to reduce the lifecycle carbon intensity – the greenhouse gas emissions per unit of energy provided – of the fuels we use. We can reduce the lifecycle carbon intensity of gasoline and diesel by blending them with ethanol, biodiesel or renewable diesel, which are renewable fuels produced from organic matter like agricultural waste and plant oils. Renewable fuels produce fewer greenhouse gas emissions than fossil fuels, even when taking a lifecycle approach that accounts for the emissions associated with land clearing and other agricultural practices that may be needed to produce the fuels.[10,11] Renewable fuels also protect local air quality because they produce fewer harmful tailpipe emissions than gasoline and diesel.

ACTIONS

T9.	Require all diesel fuel sold in Yukon for transportation to align with the percentage of biodiesel and renewable diesel by volume in leading Canadian jurisdictions beginning in 2025, aiming for around 20 per cent.	ENV
T10.	Require all gasoline sold in Yukon for transportation to align with the percentage of ethanol by volume in leading Canadian jurisdictions beginning in 2025, aiming for around 10 per cent.	ENV

Increase the use of public and active transportation.

Increasing the number of people who walk, bike and use public transit is another key way to lower greenhouse gas emissions. By reducing the number of people driving vehicles, investments in public and active transportation also reduce congestion, improve air quality and help people lead active, healthy lives. Making it easier to get around without a vehicle can also contribute to more inclusive communities by providing an accessible and affordable way to get from one place to another. While transportation options in and around Whitehorse are key to reducing greenhouse gas emissions, we will also look for public and active transportation solutions in and between Yukon's smaller communities.

Our target is for the percentage of commuting trips in Whitehorse made by drivers in single occupant vehicles to decrease to 55 per cent of all trips by 2031, as set out in the City of Whitehorse's Transportation Demand Management Plan.

10 Natural Resources Canada, 2020. "Biodiesel." https://www.nrcan.gc.ca/energy/efficiency/energy-efficiency-transportation-and-alternative-fuels/alternative-fuels/biofuels/21609

11 Natural Resources Canada, 2020. "Ethanol." https://www.nrcan.gc.ca/energy-efficiency/energy-efficiency-transportation/alternative-fuels/biofuels/ethanol/3493

ACTIONS

T11.	Provide rebates to encourage the purchase of electric bicycles for personal and business commuting beginning in 2020.	EMR
T12.	Continue to support municipalities and First Nations to make investments in public and active transportation infrastructure.	CS
T13.	Continue to incorporate active transportation in the design of highways and other Government of Yukon transportation infrastructure near communities.	HPW

Reduce the carbon footprint from medium and heavy-duty vehicles.

Yukoners rely heavily on goods brought up from southern Canada and around the world. While we are making progress toward meeting more of our needs locally, shipping of food, fuel, and other products will continue to be an important part of our lives and economy, given Yukon's relative remoteness. We also rely on medium duty vehicles like school buses, road clearing equipment and mail delivery vans to keep communities safe and accessible and to meet our daily needs. We will work to find efficiencies and reduce emissions from medium and heavy-duty vehicles.

ACTIONS

T14.	Update the Government of Yukon's heavy-duty vehicle fleet by 2030 to reduce greenhouse gas emissions and fuel costs.	HPW
T15.	Begin a pilot project in 2021 to test the use of short-haul medium and heavy-duty electric vehicles for commercial and institutional applications within Yukon.	EMR
T16.	Train the Government of Yukon's heavy equipment operators on efficient driving techniques for all new equipment by 2022.	HPW

Be more efficient in how and when we travel.

The COVID-19 pandemic has proven that we can be much more efficient in how and when we travel. It is possible for a significant number of people to work from home, reducing congestion and air pollution while continuing to deliver results. Large meetings and conferences can successfully be held through videoconferencing technology, rather than flying thousands of kilometres for a few hours of interaction. As we emerge from the COVID-19 pandemic, we will continue to invest in technology that allows us to move ideas rather than people and to pursue long-term changes to how we work and travel. Recognizing that face-to-face interactions are important, when we do travel, we will make sure we do so efficiently such as by using efficient vehicles and carpooling with colleagues or friends. These efforts will help Yukoners save money while also reducing greenhouse gas emissions, cutting back on congestion, reducing our dependence on fossil fuels, making roads safer and reducing air pollution.

Safer and more efficient driving behaviours like slower acceleration, more measured braking and driving the speed limit can increase the fuel efficiency of your vehicle by up to 25 per cent.
Source: Government of Canada, 2020. "Fuel Efficient Driving Techniques."

ACTIONS

T17.	Expand the Government of Yukon's video and teleconferencing systems and require employees to consider these options when requesting permission for work travel by 2022.	HPW
T18.	Implement new policies to enable Government of Yukon employees in suitable positions to work from home for the longer term by 2022.	PSC
T19.	Develop a planning and engagement strategy by 2022 to change how and where Government of Yukon employees work by providing choices and flexibility through a modern workplace.	HPW
T20.	Develop and implement a system by 2021 to coordinate carpooling for Government of Yukon staff travelling by vehicle for work within Yukon.	HPW
T21.	Develop guidelines for the Government of Yukon Fleet Vehicle Agency's fleet by 2021 to ensure appropriate vehicles are used for the task at hand.	HPW
T22.	Incorporate fuel efficiency into purchasing decisions for Government of Yukon fleet vehicles beginning in 2020 to reduce greenhouse gas emissions and fuel costs.	HPW
T23.	Expand virtual health care services to Whitehorse medical clinics by 2022 in order to improve access to healthcare while reducing greenhouse gas emissions from travel to and from Whitehorse.	HSS
T24.	Continue to operate the Yukon Rideshare program to make carpooling and other shared travel easier.	ENV

Ensure roads, runways and other transportation infrastructure are resilient to the impacts of climate change.

Climate change is already affecting Yukon's transportation infrastructure. Thawing permafrost damages our roads, runways and bridges and increases maintenance costs. Landslides, flooding, forest fires and other natural hazards can wash out roads, cutting communities off from critical supply routes. It is important that we address the impacts of climate change on our transportation infrastructure to ensure we stay safe and connected and to protect our economy and livelihoods.

ACTIONS

T25.	Complete a climate change vulnerability study of the road transportation network by 2023 to inform the development of standards and specifications.	HPW
T26.	Establish a geohazard mapping program for major transportation corridors and prioritize sections for targeted permafrost study by 2022.	EMR
T27.	Analyze flood risk along critical transportation corridors at risk of flooding by 2023.	ENV
T28.	Continue to conduct climate risk assessments of all major transportation infrastructure projects above $10 million[12], such as through the federal Climate Lens assessment.	HPW

Alaska Highway.

12 $10 million dollars is the threshold established by the Government of Canada for climate risk assessments through the Climate Lens.

Area #2: Homes and buildings

Many Yukoners spend a lot of time inside, whether at home, at work or at school. How we design, use and heat these buildings affects our comfort, safety, productivity, health and finances.

Right now, many buildings use more energy than they need to and heating buildings accounts for 21 per cent of Yukon's greenhouse gas emissions. Taking steps to use less energy saves money, stimulates the economy and supports green jobs in construction. Improving energy efficiency is a key step toward significant greenhouse gas reductions through heating highly efficient buildings with low-carbon energy sources like wood and clean electricity.

The Government of Yukon will lead by example in this area by undertaking energy efficiency retrofits and installing renewable heating systems to reduce greenhouse gas emissions from Government of Yukon buildings by 30 per cent by 2030, compared to 2010.

At the same time as we make our buildings more efficient, we can ensure they are designed to be more resilient to fires, floods, permafrost thaw and heat stress. This will reduce long-term repair and maintenance costs, health risks like mould, and improve public safety.

Homes and buildings objectives at a glance

Improve the energy efficiency and climate resilience of existing homes and buildings.
Ensure **new** homes and buildings are built to be low-carbon and climate-resilient.
Increase the use of biomass and other renewable energy sources for heating.
Use energy more efficiently and better align energy supply and demand.

The Government of Yukon will invest $30 million dollars on average each year in energy retrofits for homes and buildings. This will include financial support for individuals and businesses, support for First Nations and municipal governments, and retrofits to Government of Yukon buildings.

Improve the energy efficiency and climate resilience of existing homes and buildings.

Many existing homes and buildings can be improved to use less energy and to be more resilient to the impacts of climate change. The energy efficiency of our homes and buildings is affected by insulation, draftiness, and the mechanical and electrical systems we use for heat and power. Similarly, how many trees surround our buildings affects our vulnerability to forest fires while our foundation and roof affect our resilience to flooding and permafrost thaw. Taking action to improve existing homes and buildings will lead to many benefits for Yukoners, from saving money on heating and electricity to improving comfort and safety. It is important that our efforts in this area are accessible to all Yukoners, including tenants and home and building owners.

Our target is to complete 2,000 residential, commercial and institutional energy efficiency retrofits by 2030.

The amount of money paid by insurance companies in Canada for property damage due to severe weather has increased from $400 million per year in the 1980s to over one billion dollars per year. This is contributing to substantial increases in premiums for home and property insurance across Canada.
Source: Globe and Mail, 2018. "The costs of climate change are rising."

Home with solar panels.

ACTIONS

H1.	Conduct retrofits to Government of Yukon buildings to reduce energy use and contribute to a 30 per cent reduction in greenhouse gas emissions by 2030.	HPW
H2.	Conduct energy assessments of Government of Yukon buildings to identify opportunities for energy efficiency and greenhouse gas reductions, with the first period of assessments completed by 2025 and the second period completed by 2030.	HPW
H3.	Provide low-interest financing to support energy efficiency retrofits to homes and buildings beginning in 2021.	EMR & CS
H4.	Continue to provide financial support to assist First Nations and municipalities to complete major energy retrofits to institutional buildings across Yukon, aiming for 30 retrofits by 2030.	EMR
H5.	Continue to provide financial support for municipal and First Nations energy efficiency projects.	CS
H6.	Continue to work with Yukon First Nations to retrofit First Nations housing to be more energy efficient.	YHC
H7.	Continue to retrofit Government of Yukon community housing to reduce greenhouse gas emissions in each building by 30 per cent.	YHC
H8.	Continue to provide rebates for thermal enclosure upgrades and energy efficient equipment to reduce energy use in homes and commercial buildings.	EMR
H9.	Assess ways to ensure Yukoners can access adequate insurance for fires, floods and permafrost thaw by 2023.	CS
H10.	Develop and implement a plan by 2024 to conduct routine monitoring of the structural condition of Government of Yukon buildings located on permafrost.	HPW
H11.	Assess options to provide financial support for actions to improve the climate resiliency of homes and buildings by 2023.	ENV

Ensure new homes and buildings are built to be low-carbon and climate-resilient.

It is also important that new buildings are built to be low-carbon and climate-resilient from the beginning. Making sure new homes and buildings are built to energy efficient standards and with the potential impacts of climate change in mind will save money for homeowners and building owners over the long run, decrease pressure on the electrical grid, reduce greenhouse gas emissions and improve safety and comfort.

Across Canada, governments are working together toward net-zero energy ready buildings. This means buildings will be designed to be so energy efficient they could be heated and powered with just the energy from onsite renewables. In general, this means that new buildings in Canada will be designed to be 50 to 70 per cent more energy efficient than currently required by the 2015 National Building Code. The Government of Yukon will work with the Government of Canada to ensure new codes are suitable to northern Canada. Close to two-thirds of new homes in Whitehorse are already being built near this standard thanks to rebates from the Energy Solutions Centre.

ACTIONS

H12.	Work with the Government of Canada to develop and implement building codes suitable to northern Canada that will aspire to see all new residential and commercial buildings be net zero energy ready by 2032.	CS
H13.	Continue to require all new Government of Yukon buildings to be designed to use 35 per cent less energy than the targets in the National Energy Code for Buildings, in accordance with the Government of Yukon's Design Requirements and Building Standards Manual.	HPW
H14.	Adopt and enforce relevant building standards by 2030 that will require new buildings to be constructed to be more resilient to climate change impacts like permafrost thaw, flooding and forest fires.	CS
H15.	Continue to conduct climate risk assessments of all major building projects over $10 million that are built or funded by the Government of Yukon.	CS & HPW
H16.	Continue to provide rebates for new homes that are net zero energy ready, aiming for 500 homes by 2030.	EMR

Increase the use of biomass and other renewable energy sources for heating.

Increasing how much of our heating needs are met through local renewable sources will reduce greenhouse gas emissions and support the local economy. In the near term, our renewable heat options are electricity produced from renewable sources as well as wood and other forms of biomass energy. In the longer term, other forms of renewable heat like geothermal energy may also help meet our heating needs. When it comes to electric heating, we will focus on efficient, smart electric heating technologies like air source heat pumps with utility-controlled electric thermal storage that use less electricity than electric baseboards and have a significantly lower impact on peak electricity demand. For wood heating, we will focus on large commercial and government buildings with significant heating demand that will use large, efficient biomass systems with fewer air emissions. Local, sustainably harvested biomass to meet this heating demand is a low-carbon and renewable energy source that will support jobs in Yukon's wood products industry and help to reduce the risk of forest fires around Yukon communities.

Our targets are to replace 1,300 residential fossil fuel heating systems with smart electric heating systems and to support businesses, organizations and local governments to install 20 commercial and institutional biomass heating systems by 2030.

Biomass energy use can be a win-win for greenhouse gas reduction and climate change adaptation. The Government of Yukon has made it easier for Yukoners to use wood from Firesmarting and other forest fuel risk reduction efforts to heat homes and buildings. In particular, changes to the permits issued under the Forest Resources Act now allow private companies to collect wood from land clearing projects.

ACTIONS

H17.	Install renewable heat sources such as biomass energy in Government of Yukon buildings by 2030 to create long-term demand for renewable heating and contribute to a 30 per cent reduction in greenhouse gas emissions.	HPW
H18.	Provide low-interest financing to install smart electric heating devices in residential, commercial and institutional buildings in collaboration with Yukon's public utilities beginning in 2021.	EMR & CS
H19.	Provide low-interest financing to install biomass heating systems in commercial and institutional buildings beginning in 2021.	EMR & CS
H20.	Continue to assist First Nations to complete feasibility studies for the installation and operation of biomass heating systems.	EMR
H21.	Continue to provide rebates for residential, commercial and institutional biomass heating systems and smart electric heating devices and increase the current rebate for smart electric heating devices beginning in 2020.	EMR

H22.	Work with local industry to install and test 25 electric heat pumps with backup fossil fuel heating systems or utility-controlled electric thermal storage from 2020 to 2023.	EMR
H23.	Identify regulatory improvements that could support the growth of Yukon's biomass energy industry during the review of the *Forest Resources Act* by 2022.	EMR
H24.	Amend the *Air Emissions Regulations* by 2025 in order to regulate air emissions from commercial and institutional biomass burning systems to minimize the release of harmful air pollutants.	ENV
H25.	Analyze and compare the climate benefits of different types of biomass harvesting and use in Yukon by 2021 in order to identify recommended forest management practices to guide sustainable and low-carbon biomass use.	ENV

Use energy more efficiently and better align energy supply and demand.

Energy use is affected by how much we heat our buildings, whether we leave the lights on when we leave the house, what appliances we buy, and other behaviours. Using energy more efficiently will help Yukoners save money and reduce greenhouse gas emissions. It is also important to align the timing of when people use energy with when energy is available to us through demand-side management. For example, we can shift energy use away from peak times to other times when fewer people are using energy.

Demand-side management (DSM) includes a variety of tools to adjust demand for electricity. DSM initiatives can reduce the amount of electricity that people use at peak times or shift energy use away from peak times. DSM tools include financial incentives like time-of-use rates, utility control of household and business energy use, and education to change behaviour.

ACTIONS

H26.	Provide direction to the Yukon Utilities Board in 2020 to allow Yukon's public utilities to partner with the Government of Yukon to pursue cost-effective demand-side management measures.	YDC
H27.	Establish a partnership between the Government of Yukon, Yukon Energy Corporation and ATCO Electric Yukon by 2021 that will collaborate on the delivery of energy and capacity demand-side management programs.	EMR & YEC
H28.	Complete the Peak Smart pilot project by 2022 to evaluate the use of smart devices to shift energy demand to off-peak hours.	YEC
H29.	Implement an education campaign for Government of Yukon building occupants and visitors by 2026 to encourage more energy efficient behaviours.	HPW

Area #3: Energy production

While over 90 per cent of the electricity we generate in Yukon comes from renewable sources, only 26 per cent of the heat energy we use is from renewable sources, with the rest coming from non-renewable sources like diesel and propane. Overall, about 24 per cent of the energy we use in Yukon comes from renewable resources. [13]

Our approach to energy production will see more renewable energy produced for both heating and electricity, combined with upgrades to the electricity grid and energy storage to make the best use of seasonal resources. This will allow us to continue to heat and power our lives with clean energy even as electricity demand grows and as we use more electricity for transportation and heating. Our efforts to produce more energy from renewable sources will work hand-in-hand with efforts to make our homes and buildings more energy efficient in order to decrease our dependance on fossil fuels and minimize the amount of electricity we generate from diesel and natural gas. At the same time, we will make sure our electricity generation, distribution and transmission infrastructure is climate-resilient so Yukoners continue to have access to safe and reliable power.

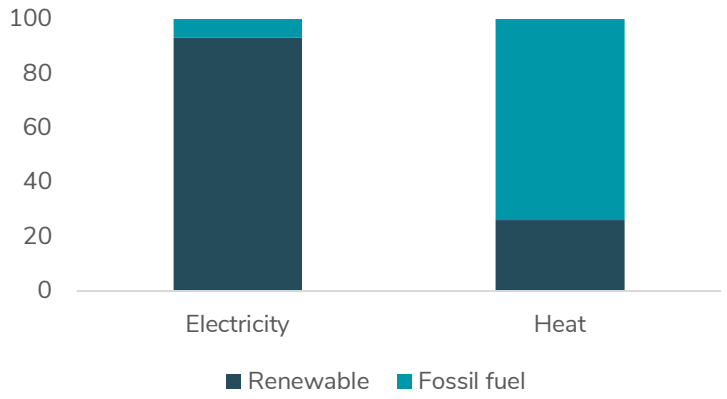


Figure 7. The percentage of electricity and heat energy that is produced by renewable sources and fossil fuels (2016).

Energy production objectives at a glance

CO_2 ⚡ $	Increase the supply of electricity generated from renewable sources.
CO_2 ⚡ $	Support local and community-based renewable energy projects for heating and electricity.
🏛 $	Ensure electricity generation, transmission and distribution infrastructure is resilient to the impacts of climate change.

13 Government of Yukon, 2018. Yukon's Energy Context.

Increase the supply of electricity generated from renewable sources.

It is important to increase the amount of electricity we produce from renewable sources as electricity demand grows and as we increasingly use electricity for transportation and heating needs. While most of our electricity currently comes from hydro, we also have other renewable energy sources available like wind, wood, solar and geothermal. Producing more of our electricity with local renewable energy will make us more self-sufficient and less vulnerable to changing fuel prices. Making sure we continue to supply most of our electricity through renewable sources is key to reducing our greenhouse gas emissions.

Through the Government of Yukon's Independent Power Production Policy and Micro-generation Program, Yukon communities and households can generate clean electricity and sell power to the grid. Participating households in the Micro-generation Program have earned close to $700 per year on average by selling excess electricity to the grid.

ACTIONS

E1.	While aiming for an aspirational target of 97 per cent by 2030, develop legislation by 2023 that will require at least 93 per cent of the electricity generated on the Yukon Integrated System to come from renewable sources, calculated as a long-term rolling average.	EMR & YDC
E2.	Require some of the diesel used to generate electricity on the Yukon Integrated System and in off-grid communities to be substituted with clean diesel alternatives like biodiesel and renewable diesel beginning in 2025, aiming for around 20 per cent.	EMR
E3.	Update the *Public Utilities Act* by 2025 to ensure an effective and efficient process for regulating electricity in Yukon.	JUS & EMR
E4.	Install renewable electricity generation systems in 5 Government of Yukon buildings in off-grid locations by 2025 to reduce reliance on diesel-generated electricity.	HPW
E5.	Evaluate the potential to generate renewable electricity at remote historic sites co-managed by the Government of Yukon and Yukon First Nations by 2022.	TC

Support local and community-based renewable energy projects.

Local and community-based renewable energy projects create jobs and opportunities across Yukon, support self-sufficiency and help Yukoners be part of the clean energy economy. Through this strategy, we will support communities and individuals to produce local renewable energy for heating and electricity, while creating opportunities for local businesses and contractors. We will also stay up-to-date on new and emerging energy technologies that may be able to meet Yukon's needs in the future, such as nuclear energy, and increase our knowledge of renewable and low-carbon energy sources that may be available in Yukon.

Our target is to have an operating independent power production project in all off-grid communities by 2030 in order to reduce diesel use for electricity generation by 30 per cent by 2030.

ACTIONS

E6.	Continue to provide financial and technical support for Yukon First Nations, municipalities and community organizations to undertake community-led renewable energy projects.	YDC
E7.	Work with Yukon's public utilities to continue to implement the Independent Power Production Policy that enables independent power producers, including Yukon First Nations and communities, to generate and sell electricity to the grid.	EMR
E8.	Increase the limit of the Standing Offer Program under the Independent Power Production Policy from 20 gigawatt hours (GWh) to 40 GWh by 2021 to support additional community-based renewable energy projects on Yukon's main electrical grid.	EMR
E9.	Develop a framework by 2022 for First Nations to economically participate in renewable electricity projects developed by Yukon's public utilities.	YDC
E10.	Continue to deliver the Micro-generation Program in collaboration with Yukon's public utilities, targeting 7 megawatts (MW) of installed renewable electricity capacity by 2030.	EMR
E11.	Develop legislation by 2023 to regulate geothermal energy development in Yukon.	EMR
E12.	Research the potential to use geothermal energy for heating and electricity, with a focus along Yukon fault systems, by 2025.	EMR

Transformer station.

Ensure electricity generation, transmission and distribution infrastructure is resilient to the impacts of climate change.

The impacts of climate change and extreme weather events can negatively affect electricity infrastructure like power lines. Climate change is also affecting rain, snowfall and glacier melt in Yukon, which in turn can impact our hydro-based electricity system. The Government of Yukon, through the Yukon Energy Corporation, is responsible for the safe and effective management of our electrical systems. Proactive climate change risk management is an operating imperative. This involves conducting research, forecasting future conditions, identifying risks and opportunities, developing adaptation options, and incorporating climate change into long-term planning and decision making.

ACTIONS

E13.	Improve modelling of the impacts of climate change on hydroelectricity reservoirs by 2021 and incorporate this information into short, medium and long-term forecasts for renewable hydroelectricity generation.	YEC
E14.	Develop a climate change adaptation plan for the Yukon Energy Corporation by 2022 that will identify risks and appropriate responses to ensure Yukon's main electrical grid is resilient to the impacts of climate change.	YEC
E15.	Implement a glacier monitoring program in 2020 to improve our ability to predict the impacts of glacier melt on hydrological systems and hydroelectricity generation.	EMR

Area #4: People and the environment

Yukoners have a strong connection to the land.

We value and depend on our natural spaces, wild animals, and clean air and water. For Indigenous people in particular, a long history of taking care of the land has shaped and continues to shape Indigenous cultures, identities and worldviews. The connection that Indigenous people have with the land, water, and animals is also a source of strength, understanding, and resilience.

Because of the intimate relationship between people and the environment, particularly the relationships nurtured by Indigenous people over generations, climate change has significant ripple effects on ways of life, cultural identities and physical and mental health. Furthermore, the impacts of climate change interact with other pressures on ecosystems like land development, resource extraction and forest fires, resulting in cumulative effects on people and the environment. These effects can diminish other important services that healthy ecosystems provide for us like clean air and pure water.

As the climate continues to change, it is important to improve our understanding of how the natural environment is responding, using a combination of Indigenous, local and scientific knowledge and ways of knowing, doing and being. Prepared with this information, we will take action to protect the ecosystems, wild species and their habitats that are so important to Yukoners. We will strive to maintain and strengthen cultural practices, recognizing that our ways of life are often interconnected with the land. We will also protect and enhance the health and wellbeing of Yukoners, which are dependent on the health of the natural environment.

People and the environment objectives at a glance

	Respond to the impacts of climate change on wild species and their habitats.
	Maintain our ability to practice traditional and cultural activities on the land.
	Protect and enhance human health and wellbeing in a changing climate.

Respond to the impacts of climate change on wild species and their habitats.

Climate change is putting pressure on ecosystems, wild species and their habitats. Species ranges are projected to shift, snowpacks may become deeper, and streams are anticipated to change in flow, temperature and sediment levels. Extreme weather events, changes to the availability of prey and forage, and conditions favourable to new and invasive species will negatively affect native species and existing ecosystems, adding to the cumulative stress they are experiencing. In response, wild species may migrate to a new location, adapt, persist or decline. Ecosystems will be reconfigured with new assemblages of plants and animals, resulting in different and unpredictable ecological processes. Some ecosystems, such as wetlands, will be more susceptible than others. It is important that we better understand how climate change is affecting the natural environment and take action to minimize the impacts on ecosystems, wild species and their habitats, and the people that depend on them.

ACTIONS

P1.	Establish a standardized method to determine the health status of wetland ecosystems and complete a pilot study to measure the baseline conditions of various reference wetlands by 2022 to better understand future changes.	ENV
P2.	Adapt existing surface and groundwater monitoring networks by 2026 to be able to track long-term trends in water quality and quantity in a changing climate.	ENV
P3.	Continue to lead and participate in projects that improve our understanding of how climate change is affecting ecosystems, wild species and their habitats.	ENV & EMR
P4.	Continue to monitor key species that will provide an indication of the impacts of climate change on Yukon ecosystems and expand monitoring to more taxonomic groups.	ENV
P5.	Continue to incorporate climate change into the design of protected and managed areas using landscape conservation science in order to allow native species to move, adapt and survive in the face of climate change.	ENV
P6.	Continue to track new and invasive species to Yukon that could impact ecosystems and biodiversity.	ENV

People searching for species during BioBlitz in Tombstone Territorial Park.

Maintain our ability to practice traditional and cultural activities on the land.

Many people go out on the land to hunt, fish, harvest, travel from one community to another, and pursue other traditional and cultural activities. These activities are a critical part of culture and identity, particularly for Indigenous people. However, climate change is threatening the safety of these activities as weather, ice and trail conditions become increasingly unpredictable, even for highly experienced people in our communities. Climate change is also affecting when and where animals, fish and berries can be harvested, and may negatively impact the health or abundance of the species upon which people have traditionally relied. As the climate continues to change, cultural and historic sites that reflect past relationships with the land may be uncovered or threatened. We will work to maintain the ability to practice traditional and cultural activities on the land in order to sustain Yukon's rich and vibrant cultures and identities.

ACTIONS

P7.	Work with Yukon First Nations to develop a tailored hunter education program by 2023 that can be adapted and delivered by Yukon First Nations for First Nations citizens.	ENV
P8.	Work collaboratively with First Nations and the Inuvialuit to document information from historic sites and culturally important places on the North Slope that are at risk due to climate change by 2024.	TC

Cow moose with two calves.

Protect and enhance human health and wellbeing in a changing climate.

Climate change can negatively affect physical and mental health in many ways. Increased smoke from wildfires, new diseases, contaminants released from thawing permafrost, warmer temperatures and challenges harvesting traditional foods can all lead to respiratory, nutritional and other health concerns. At the same time, changes to the natural environment and to land-based cultural practices and livelihoods can cause anxiety and distress as we see our home changing before our eyes. It is important that we understand how climate change is impacting our health and take action to minimize these impacts. Beyond minimizing impacts, we should also strive to enhance our health and wellbeing so that we are more resilient to the changes that are coming.

ACTIONS

P9.	Provide training to healthcare providers beginning in 2023 to be better able to identify and treat the physical and mental health impacts of climate change.	HSS
P10.	Incorporate climate-related illnesses like heat stroke, respiratory illness, and vector-borne diseases into the new *1Health Yukon* health information system by 2023 to enable tracking of climate-related illnesses in Yukon.	HSS
P11.	Expand monitoring of concentrations of particulate matter in the air from biomass burning and forest fires to all Yukon communities by 2023.	ENV
P12.	Purchase a moveable clean air shelter by 2021 that can be set up in communities to protect public health during wildfire smoke events.	HSS
P13.	Provide financial support to vulnerable Yukoners to install cleaner air spaces in their homes and buildings beginning in 2023 to provide protection from wildfire smoke.	YHC
P14.	Analyze existing information on food insecurity in Yukon by 2023 to inform the development of a system to gather food insecurity data into the future.	HSS & EMR

Area #5: Communities

Dawson City.

Yukon is home to many unique, vibrant communities where we live, work, play and celebrate our cultures.

This strategy takes proactive steps to ensure our communities will be strong and resilient into the future. Our communities will increasingly be places where people walk, cycle and use public transportation to get around and where local businesses thrive. Our communities will be more resilient to the impacts of climate change and increasingly self-sufficient when it comes to food production.

Communities objectives at a glance

CO₂ ⚡	Design our communities to be low-carbon and resilient to the impacts of climate change.
	Ensure we are prepared for emergencies that are becoming more likely due to climate change.
CO₂	Supply more of what we eat through sustainable local food production.

Design our communities to be low-carbon and resilient to the impacts of climate change.

The ways our communities are designed affects how easy it is to walk to work, take public transit, or use renewable energy sources for heating and electricity. The design of communities and the underlying infrastructure also affects our ability to provide critical services like healthcare, clean and safe drinking water and waste management. Moving forward, we will focus on making communities more compact and efficient rather than expanding outwards, and make sure our homes are close to the places where we work and play. We will ensure that our communities are designed in ways that reduce our vulnerability to forest fires, permafrost thaw, flooding, drought and other natural hazards that are expected to worsen with climate change.

Building infrastructure to be climate-resilient adds about three per cent to the upfront cost. However, this investment pays back at about four times the amount invested due to lower repair costs and a longer useable lifespan. Engineers and planners can follow the Government of Canada's Climate Lens guideline to help them design resilient infrastructure.

Source: Global Comission on Adaptation, 2019. Adapt Now: A Global Call for Leadership on Climate Resilience.

ACTIONS

C1.	Expand geohazard map coverage to all Yukon communities with a high risk of permafrost thaw by 2025.	EMR
C2.	Develop flood probability maps for all Yukon communities at risk of flooding by 2023 that incorporate climate change projections.	ENV
C3.	Develop detailed guidelines by 2025 that can be used by the Government of Yukon and partners to develop walkable, bike-friendly and transit-oriented communities.	ENV
C4.	Continue to develop, encourage and apply applicable climate resiliency standards to community design and infrastructure development projects built by or receiving capital funding from the Government of Yukon.	CS
C5.	Continue to conduct detailed climate change risk assessments of all major community infrastructure projects over $10 million that are built or funded by the Government of Yukon.	CS
C6.	Continue to make recommendations to consider the impacts of climate change in regional land use and local area planning processes, which inform the Government of Yukon's development permitting and zoning decisions.	EMR
C7.	Continue to provide technical and administrative support to Yukon First Nations and municipalities to prepare integrated asset management plans.	EMR

Ensure we are prepared for emergencies that are becoming more likely due to climate change.

Climate change is increasing the likelihood of emergencies like severe forest fires and floods. Taking action to reduce the risk of these events, and ensuring we are prepared if they do happen, is critical. Through this strategy, we will work to build climate-resilient communities across Yukon and to have systems in place to effectively predict and respond to fires, floods and other emergencies like water shortages or landslides that may threaten Yukon communities.

Emergency preparedness is a good investment. As one example, for every dollar invested in effective early warning systems for floods, fires or heatwaves, taxpayers save ten dollars on average in avoided damages.
Source: Global Comission on Adaptation, 2019. Adapt Now: A Global Call for Leadership on Climate Resilience.

ACTIONS

C8.	Expand monitoring networks and improve modelling tools to generate reliable daily flood forecasts and relevant warnings for all at-risk Yukon communities by 2024.	ENV
C9.	Work with First Nations and municipalities to develop Wildfire Protection Plans for all Yukon communities by 2026 and to complete the forest fuel management activities outlined in the plans by 2030.	CS
C10.	Increase the capacity in Yukon Wildland Fire to prevent wildfires and respond to extended fire seasons by investing in staffing in 2020.	CS
C11.	Complete hazard identification and risk assessments (HIRAs) for all Yukon communities by 2022 that include climate change risks.	CS
C12.	Work with First Nations and municipalities to complete emergency management plans for all Yukon communities by 2022 informed by community hazard identification and risk assessments (HIRAs).	CS
C13.	Develop a territorial disaster financial assistance policy by 2022 to support recovery from natural disasters that result in extensive property damage or disruption to the delivery of essential goods and services.	CS

Supply more of what we eat through sustainable local food production.

Harvesting and producing more of the food we eat locally increases food security, contributes to the economy, and reduces how much food we need to ship into the territory. Local food production can include community greenhouses and gardens, backyard gardens, larger-scale agriculture and farming and small-scale animal husbandry. All these forms of local food production have an important role to play in a resilient, sustainable future that takes advantage of longer growing seasons and warmer temperatures as our climate changes.

The 2016-2021 Local Food Strategy for Yukon supports a more developed and sustainable local food system in the territory. Our Clean Future highlights the Government of Yukon's continued commitment to many relevant initiatives in the Local Food Strategy, including community food production.

ACTIONS

C14.	Incorporate support, where possible, for local food producers into Government of Yukon procurement processes beginning in 2020.	HPW
C15.	Continue to provide funding for community gardens and greenhouses, especially in rural communities.	EMR
C16.	Continue to provide technical advice to assist First Nations and municipal governments with their agricultural and animal husbandry projects.	EMR
C17.	Continue to conduct and provide access to funding for research on how climate change could affect local agriculture.	EMR
C18.	Continue to support agricultural producers to adapt to the impacts of climate change, adopt low-carbon practices and use surface water and groundwater efficiently.	EMR

Area #6: Innovation

Northlight Innovation

Innovation is new and improved ways of doing something, whether it is how we generate and use energy, how we manage waste, how we create products or how we interact with one another. Innovation can reduce the environmental impacts of existing industries and support the development of new industries. It drives economic progress and increased productivity, and helps diversify the economy.

Our approach to innovation will see continued support for Yukon's businesses, innovators and entrepreneurs through funding, procurement and skills development. We will also work to make existing industries and activities more sustainable in the long-term, including how we think about and manage waste.

Innovation objectives at a glance

CO₂ ⚡ 🌡 $	Support innovation and green business practices.
CO₂ ⚡ 🌡 $	Reduce the carbon intensity of mining and ensure mining projects are prepared for the impacts of climate change.
CO₂ ⚡ 🌡 $	Enhance the sustainability of Yukon's tourism industry.
CO₂ $	Improve how we manage our waste to move toward a more circular economy.

Support innovation and green business practices.

As we build a green economy, we will support innovation, local business development, and green business practices. Government funding and purchasing decisions will encourage businesses to use greener practices and build climate resilience into their operations, and will create demand for innovative clean technologies. We will also support businesses, organizations and communities interested in pursuing a range of projects that will support green economic development and climate resilience across Yukon. As local, national and global economies become greener, Yukoners will need new entrepreneurial, business and technical skills to fully participate in new economic opportunities. Ensuring Yukoners have these skills by predicting and adaptively assessing skills needs will help ensure equitable participation in the green economy.

The Government of Canada is working with provinces and territories to develop a Canadian greenhouse gas offset system. This system could create an economic opportunity for Yukon businesses, organizations and development corporations to generate and sell carbon offsets within Canada.

ACTIONS

I1.	Incorporate greenhouse gas emissions into the decision-making process for Department of Economic Development funding programs by 2022.	EcDev
I2.	Update the Government of Yukon's procurement policies and standards in 2020 to better support sustainable and local procurement.	HPW
I3.	Identify and develop options to address potential regulatory and policy barriers to the growth of green businesses in Yukon by 2023.	EcDev
I4.	Expand the range of relevant professional development offerings by 2023 to enable more Yukoners to participate in the green economy.	EMR
I5.	Create an award program by 2022 to recognize the achievements of local green businesses and organizations.	EcDev

Reduce the carbon intensity of mining and ensure mining projects are prepared for the impacts of climate change.

Efforts to improve energy use in all phases of mining from planning to closure – such as using more efficient equipment or generating low-carbon energy onsite – can save money, lower greenhouse gas emissions, and support corporate social responsibility efforts. As demand for metals like copper, iron and lead increases to build more solar panels and other clean energy technologies, it is important that mining activities be energy efficient. We also need to make sure that mining activities are planned and carried out with climate change in mind. Thawing permafrost, increased rainfall and other climate change impacts affect the way a mine should be designed, operated and closed.

ACTIONS

I6.	Include new provisions in quartz mine licenses by 2022 that will ensure critical mine infrastructure is planned, designed and built to withstand current and projected impacts of climate change.	EMR
I7.	Require quartz mines to project their anticipated greenhouse gas emissions, identify measures to reduce emissions, and annually report greenhouse gas emissions through the quartz mine licensing process beginning in 2022.	EMR
I8.	Increase the Government of Yukon's participation in intergovernmental initiatives related to mine resiliency, low-carbon mining and innovation by 2021.	EMR
I9.	Establish an intensity-based greenhouse gas reduction target for Yukon's mining industry and additional actions needed to reach the target by 2022.	EMR & ENV

Enhance the sustainability of Yukon's tourism industry.

The Yukon Tourism Development Strategy, released in November 2018, establishes a vision for tourism to be a vibrant, sustainable component of Yukon's economy and society for the benefit of future generations. Sustainability is at the heart of the Tourism Development Strategy, with the aim for tourism to provide Yukon with sustainable, diversified growth that balances economic development with environmental, community and cultural values. We will support sustainable tourism by measuring and monitoring sustainable tourism development and taking action based on that information to ensure tourism growth supports healthy communities, preserves our natural environment for future enjoyment, and benefits Yukoners for generations to come.

ACTIONS

I10.	Establish and implement a framework to measure the sustainability of tourism development in Yukon by 2021.	TC
I11.	Develop and implement a system to track greenhouse gas emissions from Yukon's tourism industry by 2021.	TC

Improve how we manage our waste to move toward a more circular economy.

In a circular economy, products are designed to avoid waste and pollution, products and materials are used for longer before being recycled or composted, and natural systems are regenerated. It is different from the usual linear approach of making something, using it and throwing it away. Better waste management is a key part of a circular economy, and an element that Yukon can take action on. Improved waste management includes reducing waste, repairing or remanufacturing products so they can be used longer, recycling the materials in products to use them again and composting organic materials. Moving toward a more circular economy will support economic prosperity with as little environmental impact as possible.

Our targets are to reduce the amount of waste generated per person by 10 per cent by 2030, compared to 2020, and to increase the amount of waste diverted from the landfill per person to 40 per cent by 2025.

ACTIONS

I12.	Assess options for establishing a comprehensive waste diversion system in Government of Yukon buildings, including reuse, recycling, compost and e-waste collection by 2030.	HPW
I13.	Develop legislation that will enable the Government of Yukon to restrict or prohibit the production, supply or distribution of appropriate single use bags by 2021.	ENV
I14.	Design and implement a system for Extended Producer Responsibility by 2025 that will make producers responsible for managing materials through the lifecycle of a product.	ENV

Area #7: Leadership

Drummers at White Pass & Yukon Railway.

Our Clean Future aims to empower each and every government, business and individual to take a leadership role in building a healthy, prosperous Yukon for years to come. First and foremost, we will ensure the actions we take as governments in Yukon are consistent with our vision for a healthy, resilient future by considering climate change in all our actions. We will also empower Yukon businesses, organizations, individuals and families to be part of the solution.

Leadership objectives at a glance

	Ensure the goals of this strategy are incorporated into government planning and operations.
	Educate and empower youth as the next generation of leaders.
	Ensure Yukoners have the information needed to make evidence-based decisions.

Ensure the goals of this strategy are incorporated into government planning and operations.

Building a healthy, resilient future is not something that can be done in isolation from government policy. It is important that the goals of this strategy be integrated into all aspects of government planning and operations across Yukon to ensure the actions we take are consistent with our long-term vision.

Following recent upgrades to Yukon's school curriculum, students learn about climate change from Kindergarten to Grade 12. This includes learning about the causes of climate change, how climate change affects biodiversity and ecosystem health, and learning about climate change from the perspective of Yukon First Nations.

ACTIONS

L1.	Create a Clean Energy Act by 2023 that legislates our greenhouse gas reduction targets and our commitments to energy efficiency and demand-side management to hold the Government of Yukon accountable.	EMR
L2.	Incorporate a climate change lens into the decision-making process for major Government of Yukon policies, programs and projects by 2021.	ECO
L3.	Incorporate climate change risks into Government of Yukon departmental planning processes by 2022.	ENV
L4.	Incorporate greenhouse gas emissions and energy efficiency into the process for identifying and prioritizing Government of Yukon building retrofits and new construction projects by 2023.	HPW
L5.	Develop and offer climate change training for Government of Yukon employees by 2022.	ENV

Educate and empower youth as the next generation of leaders.

Youth will be most affected by the decisions we make today. Recognizing this, many Yukon youth have already become involved in climate change, energy and green economy initiatives. This strategy will support youth to continue being involved in these important areas, educating and empowering them to step forward as the next generation of leaders. Our approach to empowering and educating youth will respect and reflect Indigenous ways of knowing, doing and being.

ACTIONS

L6.	Create a Youth Panel on Climate Change in 2020 that will provide advice and perspectives to the Government of Yukon on climate change, energy and green economy matters that reflects the diversity of Yukon youth.	ECO
L7.	Provide mentorship opportunities for Yukon youth to participate in major international climate change and energy events with Government of Yukon staff beginning in 2023.	ENV
L8.	Continue to support land-based programs in the Yukon school curriculum that teach First Nations ways of knowing and doing to youth.	EDU

Chunday K'anat'a dancers.

Ensure Yukoners have the information needed to make evidence-based decisions.

Research, knowledge and information to inform evidence-based decision-making will continue to be an important part of our efforts on climate change, energy and green economy. To take effective action, we must understand the problems we are trying to solve and the solutions that are available. This understanding should be based on respectfully bringing together Indigenous, local and scientific knowledge and ways of knowing, doing and being. Over the course of this strategy, our knowledge will evolve with advances in research, science and technology, new local observations, and progress bringing together different perspectives and ways of knowing. Respectful information sharing and collaboration across governments, businesses, organizations and individuals will help us work together to build a clean future.

ACTIONS

L9.	Assess climate hazards and vulnerabilities to those hazards across Yukon every three to four years between 2020 and 2030 to prioritize climate change adaptation actions.	ENV
L10.	Support the Government of Canada's work to develop a pan-territorial climate hub by 2030 that will support access to climate data and projections for the north.	ENV
L11.	Begin participating in the National Forest Inventory monitoring program in 2022 to gather information about forest carbon stocks, potential biomass energy supply, pest and forest fire risks, and climate impacts on Yukon's forests.	EMR
L12.	Create easy access to technical information and lessons learned about climate change, energy and green economy for governments and stakeholders by 2021.	ENV
L13.	Launch a Yukon-wide information or social marketing campaign in 2021 that will educate Yukoners on greenhouse gas emissions, renewable energy, climate change adaptation, and other topics and highlight what Yukoners can do to support climate change initiatives.	ENV

Measuring our progress

The Government of Yukon will publicly report each year on the implementation of *Our Clean Future*. The annual progress reports will include:

- the status of each action in *Our Clean Future*;
- the key indicators of progress below as well as additional indicators or information for each action in the strategy;
- the latest 2030 greenhouse gas emissions forecast for Yukon; and
- any modifications to the actions in *Our Clean Future*.

Annual public reporting combined with a new Clean Energy Act to legislate key targets in *Our Clean Future* will ensure the Government of Yukon remains transparent and accountable to Yukoners as we rise to the challenge of addressing climate change.

Key progress indicators

Goal	Indicator	Target
Reduce Yukon's greenhouse gas emissions.	• Greenhouse gas emissions from transportation, heating, electricity generation, other commercial and industrial activities, waste and other areas.	• 30 per cent reduction by 2030, compared to 2010.
	• Greenhouse gas emissions intensity of mining.	• Target will be established by 2022.
Ensure Yukoners have access to reliable, affordable and renewable energy.	• Percentage of the electricity we use on the main Yukon electricity grid that is generated from renewable sources, calculated as a long-term rolling average.	• A long-term rolling average of 97 per cent by 2030.
	• Litres of fossil fuels used to generate electricity in off-grid communities.	• 30 per cent reduction by 2030, compared to 2010.
	• Percentage of energy used for heating that is from renewable sources.	• 50 per cent by 2030.
	• Greenhouse gas emissions from road transportation.	• 30 per cent reduction by 2030, compared to 2010.
Adapt to the impacts of climate change	• A set of qualitative and quantitative indicators that will reflect Yukon's resilience to climate change.	• Highly climate resilient by 2030.
Build a green economy	• Greenhouse gas emissions per person and per unit of real gross domestic product.	• A decrease from 2020 to 2030.

Key progress indicators will also be tracked and reported for each of the seven areas of *Our Clean Future* (see table at right). Targets associated with the indicators are noted in brackets.

Area	Indicator
Transportation	• Greenhouse gas emissions from transportation.
	• Number of zero emission vehicles registered in Yukon (4,800 by 2030).
	• Carbon intensity of transportation fuels.
	• Percentage of commuting trips made by drivers in single-occupant vehicles (55 per cent by 2031).
	• Number of road kilometres at risk of permafrost thaw that have undergone geohazard mapping.
	• Number of critical transportation corridors that have been analyzed for flood risk.
Homes and buildings	• Greenhouse gas emissions from heating fuel use.
	• Dollars invested in energy retrofits ($30 million each year on average).
	• Greenhouse gas emissions from Government of Yukon buildings (30 per cent reduction by 2030, compared to 2010).
	• Number of energy efficiency retrofits to residential, commercial and institutional buildings (2,000 by 2030).
	• Average percentage of new homes with energy performance above code.
	• Number of fossil fuel heating systems converted to smart electric heating systems (1,300 by 2030).
	• Number of commercial and institutional biomass energy systems (20 by 2030).
	• Gigawatt hours (GWh) of electricity demand avoided through demand-side management.
Energy production	• Greenhouse gas emissions from electricity generation.
	• Gigawatt hours (GWh) of energy generated from renewable sources.
	• Installed renewable electricity capacity in megawatts (MW).
	• Proportion of off-grid communities with operating renewable electricity projects (all off-grid communities by 2030).
	• Number of large-scale renewable heating projects.
Communities	• Proportion of at-risk communities that geohazard mapping has been completed for (all at-risk communities by 2024).
	• Proportion of at-risk communities that flood maps have been completed for (all at-risk communities by 2030).
	• Proportion of communities that Wildfire Protection Plans have been completed for (all communities by 2021).
People and the environment	• Number of cases of climate-related illnesses.
	• Proportion of Yukon communities with air quality monitoring (all communities by 2023).
	• Percentage of Yukoners that are food insecure.
Innovation	• Number of Yukoners that have participated in green economy professional development opportunities.
	• Proportion of quartz mines covered by new greenhouse gas reporting and climate resilience requirements.
	• The results of Yukon's sustainable tourism measurement framework.
	• Per capita waste generation in Yukon (10 per cent reduction by 2030, compared to 2020).
	• Per capita waste diversion in Yukon (40 per cent by 2030).
Leadership	• Number of Government of Yukon staff that have completed climate change training.

Prioritization

The objectives and actions in *Our Clean Future* went through a detailed prioritization process to make sure we are investing time and resources in the best ways to reduce greenhouse gas emissions, enhance energy security, adapt to the impacts of climate change and build Yukon's green economy.

Objectives

In fall 2018, the Government of Yukon worked with Indigenous and municipal partners to gather ideas about what a new climate change, energy and green economy strategy for the territory could include. Through public meetings, youth events, and input from stakeholders, experts and industry groups, numerous ideas were brought forward.

To decide which of these areas we should focus our efforts on, the Government of Yukon worked with Indigenous and municipal partners to jointly establish a set of decision-making criteria. The criteria were applied to each of the potential areas for action to inform which areas we should focus on. We used multiple criteria because deciding what to focus on is complex and cannot be determined by looking at any one factor alone.

Decision-making criteria

Effectiveness

How much could taking action in this area reduce greenhouse gas emissions, enhance energy security, increase climate resilience or build a green economy?

Economic effects

Could taking action in this area positively or negatively affect the economy?

Feasibility

How feasible it is to take action in this area over the next 10 years?

Societal effects

Could taking action in this area positively or negatively affect social equity and community wellbeing?

Participant interest

To what degree were participants in the public engagement interested in seeing action taken in this area?

Public health effects

Could taking action in this area positively or negatively affect public health?

Cost effectiveness

How cost effective would it be to take action in this area?

Environmental effects

Could taking action in this area positively or negatively affect the environment?

To assess each potential area of action using the criteria above, the Government of Yukon drew on several sources of expertise, including:

- "Yukon Greenhouse Gas Mitigation Analysis" by Vector Research that compiled climate change and energy programs and policies from other jurisdictions that may be appropriate to Yukon;
- "Yukon Greenhouse Gas Mitigation Analysis: Part II: Prioritization of Practical Greenhouse Gas Emissions Mitigation Measures" by Vector Research that estimated the cost per tonne and greenhouse gas reduction potential of various measures to reduce emissions;
- "Evaluation of Opportunities in a Green Economy in Yukon" by Research Northwest that identified the core components of Yukon's green economy and potential green economic opportunities;
- Early findings from the Government of Yukon's corporate climate change risk assessment regarding key climate hazards and areas of vulnerability that may be applicable to Yukon as a whole; and
- The Government of Yukon's Women's Directorate regarding potential societal effects.

Copies of the reports listed above can be found on Yukon.ca.

After applying the criteria to each potential area that we could focus on, the Government of Yukon brought a proposed list of focus areas to Indigenous and municipal partners for discussion. The final focus areas from that discussion became the objectives in *Our Clean Future*.

Actions

The Government of Yukon's actions in *Our Clean Future* were developed to work toward the objectives identified with Indigenous and municipal partners. The Government of Yukon's actions were informed by several factors, including:

- Policies and programs implemented in other jurisdictions, and the lessons they learned in the process;
- Lessons learned from previous and current climate change and energy initiatives in Yukon;
- Climate change and energy research and studies from Yukon and across Canada;
- Ideas and suggestions from experts, stakeholders, and industry members;
- Public interest in certain actions as communicated thorugh the first and second public engagements on *Our Clean Future*; and
- Energy-economy modelling completed by Navius Research.

Energy-economy modelling

The Government of Yukon worked with Navius Research to develop an energy-economy model for Yukon that can assess the possible greenhouse gas reduction and economic impacts of different actions to reduce emissions. The model can also identify ways to reduce greenhouse gas emissions most cost effectively.

The first step of model development was to calibrate the model based on Yukon's historical greenhouse gas emissions and various other pieces of information like energy use, the types of heating systems used in buildings, and economic activities.

The next step was to incorporate the greenhouse gas reduction policies and programs that were already in place in Yukon prior to *Our Clean Future* into the model, such as energy efficiency rebates offered by the Government of Yukon's Energy Branch. This resulted in a forecast of what Yukon's greenhouse gas emissions might look like if we continued with current initiatives only – referred to as the "reference case" or "business as ususal" scenario.

The final step of the modelling was to incorporate potential new policies and programs into the model. The resulting greenhouse gas reduction and economic impacts forecasted by the model were then used to tweak and finalize new policies and programs, and to estimate the total greenhouse gas reduction that we will achieve through the actions in *Our Clean Future*.

The energy-economy model will continue to be updated as we implement *Our Clean Future* to inform adjustments to the strategy to meet the 2030 greenhouse gas reduction target for Yukon.

For more information about the energy-economy modelling, please see the detailed report from Navius Research available through Yukon.ca.

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Kusawa Lake.

FBC 2023 ANNUAL REVIEW OF RATES
EXHIBIT B-2

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August 5, 2022

British Columbia Utilities Commission
Suite 410, 900 Howe Street
Vancouver, BC
V6Z 2N3

Attention: Ms. Sara Hardgrave, Acting Commission Secretary

Dear Ms. Hardgrave:

Re: FortisBC Inc. (FBC)

Multi-Year Rate Plan for 2020 through 2024 approved by British Columbia Utilities Commission (BCUC) Order G-166-20 (MRP Plan)

Annual Review for 2023 Rates

In accordance with the MRP Plan and BCUC Order G-193-22 setting out the Regulatory Timetable for FBC's Annual Review, FBC hereby attaches its Annual Review for 2023 Rates Application materials.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC INC.

Original signed:

Diane Roy

Attachments

cc (email only): Registered Interveners to the FBC Annual Review for 2022 Rates

FORTIS BC™

FORTISBC INC.

Annual Review for 2023 Rates

August 5, 2022

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1. APPROVALS SOUGHT, OVERVIEW OF THE APPLICATION AND PROPOSED PROCESS

1.1 *INTRODUCTION*

FortisBC Inc. (FBC or the Company) files this Application in compliance with British Columbia Utilities Commission (BCUC) Order G-166-20, which approved a Multi-Year Rate Plan (MRP or the Plan) for FBC for the years 2020 to 2024. In accordance with the MRP, an annual review process is required to set rates for each year of the MRP.

The MRP provides stable levels of O&M funding and includes service quality indicators (SQIs) to monitor the maintenance of service quality. The approved Earnings Sharing Mechanism (ESM), set out in Section 10, aligns the incentive properties of the Plan between customers and the Company.

As explained in Section 10 of the Application, FBC proposes to distribute $0.911 million pre-tax ($0.665 million after-tax) in earnings sharing to customers in 2023.

The proposed rates for 2023 flowing from the approved formulas and forecasts set out in the Application, including returning the actual 2021 earnings sharing to customers, result in a 3.99 percent rate increase from 2022 rates. The increase is primarily due to an increase in power purchase expense (PPE) as well as rate base growth.

In the subsections below, FBC sets out the approvals it is seeking and provides an overview of the requirements for the annual review process. This is followed by a discussion of FBC's 2021 formula O&M savings and the productivity initiatives that FBC is developing. Finally, FBC provides a summary of its proposed revenue requirements and rate changes for 2023 and a summary of the SQI results. These matters are addressed in more detail in subsequent sections of the Application.

1.2 *APPROVALS SOUGHT*

With this Application, FBC requests BCUC approval for the following pursuant to sections 59 to 61 and 89 of the *Utilities Commission Act* (UCA):

1. Approval to recover the 2023 revenue requirement and resultant rate change on an interim basis, effective January 1, 2023, as filed in the Application and subject to any adjustments identified by FBC during the regulatory process and from any directives or determinations made by the BCUC in its decision on the Application. Rates will remain interim pending the outcomes of the BCUC's current generic cost of capital (GCOC) proceeding and FBC's 2023-2027 Demand Side Management (DSM) Plan proceeding.
2. The level of forecast growth, sustainment and other capital to be incorporated in rates for the years 2023 and 2024, as set out in Section 7.2.1.

3. The following deferral account approvals, as described in Section 7.6:

   - Creation of a rate base deferral account for the 2023 Joint Pole Use Audit, with the balance in the deferral account to be amortized over five years commencing January 1, 2023; and
   - Approval of a three-year amortization period for the existing COVID-19 Customer Recovery Fund Deferral Account, commencing January 1, 2023.

4. Approval to cease reporting on the COVID-19 Customer Recovery Fund Deferral Account, as described in Section 7.6.2.1.

FBC also seeks approval pursuant to section 99 of the UCA to vary the following Orders:

1. Directive 6 of Order G-42-21 in order to facilitate the return of the net incremental COVID-19 related cost reductions to customers through inclusion of the cost reductions in the Flow-through deferral account, as described in Section 12.2.1.

2. Directive 2 of Order G-83-14 to ensure that FBC continues to have approval from the BCUC to use US GAAP for regulatory accounting purposes, as described in Section 12.3.1.

A draft order is included in Appendix D.

1.3 *REQUIREMENTS FOR THE ANNUAL REVIEW*

On page 167 of the MRP Decision, the BCUC set out its expectations for the Annual Review component of the MRP. For reference, the table below sets out each requirement and FBC's response or where it is addressed in the Application.

Table 1-1: Annual Review Requirements

Item	Description	Response or Reference
1	Review of the current year projections and the upcoming year's forecast. For further clarity, these items are listed below:	See items 1(a) to 1(f) below
1(a)	Customer growth, volumes and revenues;	Section 3
1(b)	Year-end and average customers, and other cost driver information including inflation;	Section 2
1(c)	Expenses, determined by the indexing formula plus items forecast annually;	Section 6
1(d)	Capital expenditures (as provided for by the capital forecast), plus other items forecast annually;	Section 7
1(e)	Plant balances, deferral account balances and other rate base information and depreciation and amortization to be included in rates; and	Sections 7 and 12
1(f)	Projected earnings sharing for the current year and true-up to actual earnings sharing for the prior year.	Section 10

Item	Description	Response or Reference
2	Identification of any efficiency initiatives that the Utilities have undertaken, or intend to undertake, that require a payback period extending beyond the MRP period with recommendations to the BCUC with respect to the treatment of such initiatives.	FBC has not identified any efficiency initiatives with a payback beyond the end of the MRP period
3	Review of any exogenous events that the Company or stakeholders have identified that should be put forward to the BCUC for review.	Section 12.2
4	Review of the Utilities' performance with respect to SQIs. Bring forward recommendations to the BCUC where there have been a "sustained serious degradation" of service.	Section 13
5	Assess and make recommendations with respect to any SQIs that should be reviewed in future Annual Reviews.	FBC does not have any recommendations at this time
6	Reporting on the Innovation Fund status.	Not Applicable for FBC
7	Assess and make recommendations to the BCUC on potential issues or topics for future Annual Reviews.	FBC does not have any recommendations at this time

1.4 *FORMULA O&M SAVINGS AND PRODUCTIVITY INITIATIVES*

1.4.1 Overview of 2021 Formula O&M Savings

For 2021, FBC achieved formula O&M savings in addition to meeting the embedded productivity improvement factor in the O&M formula. Total formula O&M savings before earnings sharing were approximately $3.4 million.

Approximately $0.9 million in formula O&M savings were realized due to the net incremental impact of the COVID-19 pandemic, which will be returned to customers via the Flow-through deferral account. Please refer to Section 12.2.1 for further details. Lower spending in the Finance and Information Systems departments of approximately $0.6 million from vacancies, reduced consulting, and lower computer consulting services and expenses contributed to the savings. Additionally, approximately $2.2 million of O&M savings were due to the timing of expenditures, such as vacancies and consulting expenditures, and lower general and miscellaneous expenditures. These savings were partially offset by approximately $0.3 million of higher spending compared to the formula amount for incremental expenditures related to System Operations, Integrity and Security. Please refer to Section 6.2.1 for further details. While some of the savings are one-time in nature (e.g., delay in filling vacancies), some of the savings are expected to continue into the future, recognizing that cost pressures in the future may offset the savings.

FBC will continue to pursue productivity improvements to achieve savings beyond the productivity improvement factor as it seeks to manage its business needs and cost pressures resulting from its evolving and challenging operating environment.

1.4.2 Productivity Initiatives

As mentioned in FBC's Annual Review for 2022 Rates (2022 Annual Review), in 2021, FortisBC Energy Inc. (FEI) and FBC (together FortisBC) initiated a working group consisting of senior managers and directors from different parts of the organization that is responsible for reviewing and identifying areas for productivity initiatives. An area of focus for potential productivity opportunities is initiatives that offer financial and customer service benefits and leverage technology and innovation to achieve these benefits.

Following is a summary of productivity initiatives from different parts of the organization FortisBC reviewed this past year and/or is investigating.

1. **Field Operations Improvements:** This initiative was investigated through collecting feedback and analyzing efficiency gains within FBC's Outage Management System (OMS) and Mobile Workforce Management System (MWFM). Changes have been made to the software and processes that allow for improved information sharing and functionality when dispatching and performing jobs. This allows for less manual intervention and a more streamlined workflow. On a separate, but related initiative, enhancements are also underway to provide FBC's storm response restoration teams with an improved interface to access triage information. This will allow for a better prioritization of repairs, and a more efficient allocation of the available resources, resulting in faster restorations.

2. **Use of Unmanned Aerial Vehicles (UAVs - Drones):** FBC is investigating using UAVs to perform transmission line condition assessments. In 2021, FBC requested its contractor performing condition assessments to incorporate the use of drones for collecting data for certain suspected deficiencies. This use of drones was expected to reduce the need for follow-up bucket truck inspections to confirm deficiencies that cannot be fully assessed from the ground, and allow FBC to prepare work-packages for deficiencies identified during condition assessments in a more timely manner. Additionally, some of the drone-collected data has been used to help assess potential system upgrades and reconfigurations without requiring additional field verification of existing assets. For 2022, FBC is developing a request for pricing to assess the potential efficiencies associated with a condition assessment program relying exclusively on drone-collected data and the use of artificial intelligence and machine learning to help identify and categorize deficiencies related to FBC's transmission assets. Should a proponent be identified through this process, it is expected that this work will help validate the use of these techniques for performing condition assessment work and also help quantify the potential cost-savings associated with a drone-based approach for condition assessments.

3. **Technology Investments to Support Enhanced Communications:** FBC introduced enhancements during the COVID-19 pandemic to enable employees to productively work remotely. The implementation of the Microsoft Teams platform was expedited in 2021, allowing for use of video meetings for employee communications. In 2021, FBC also introduced the Microsoft Teams mobile app that provided seamless integration and access to Teams meetings, Teams sites, calendar, chat functionality and a seamless transition

from phone to computer or vice versa during meetings. It was and continues to be a platform to reduce travel requirements for staff, providing options to meet in person less often, which enables continued savings on fuel costs, hotels, meals, and wear and tear on vehicles. Hybrid meetings support large audience attendance using Teams meetings, with the added benefit of not requiring time away from the home office and the resulting lost productivity. Additional functionality will continue to be added to the Teams platform (i.e., whiteboard, enhancements to breakout rooms, Presenter modes and group control of presentation, etc.) as Microsoft continues to develop and release upgrades. The mobile application will also see improvements.

The Company's rapid implementation of communications software during the pandemic has contributed to creating a productive work environment for employees to complete their work with the benefit of not requiring time away from the home office and lost productivity. In total, FBC invested approximately $0.2 million over the two years 2020 and 2021. This investment has contributed to achieving employee-related expense savings (i.e., travel) during the pandemic and will also help to permanently sustain some of the related savings post pandemic.

4. **Data Analytics:** This is an initiative to centralize the Company's data sources coupled with a suite of analytic tools to analyze and use the data to inform decision-making. Data analytics is the process of extracting and analyzing data sets to identify or uncover patterns, correlations, trends, customer preferences and other information for the purpose of allowing an organization to make more informed business decisions. Better decisions will lead to improved business operations and customer service and increased productivity. The ability to easily access and analyze data can be inhibited by internal processes, decentralization of information and a lack of understanding of the data. With Data Analytics, departments will be provided a common cleansed data source and the tools to create advanced analytics quickly and easily. Resources will be provided to business areas to help identify reporting and analytic needs that will lead to efficiencies. Through a centralized approach, this will provide the skills along with the data and the tools to drive business capability to support analytic needs and also provide better visibility to costs or benefits of data analytics initiatives.

   The requirements and business case for the necessary information systems infrastructure were completed in 2021. FBC plans to implement systems that will allow centralized data access in 2022 and add new data sources in priority sequence over time. Data usage cases for this initiative are being prioritized first for those that enable cost savings.

5. **Streamlining and Automating Reporting Process:** This initiative is one of the earlier usage cases that FBC is considering for the Data Analytics initiative. The focus is on streamlining the reporting processes for financial and management reporting information (i.e., internal cost reporting, key performance indicators, etc.). Currently, the reporting processes work well with clearly defined requirements and processes but rely on manual effort. Source system (i.e., SAP) reports are not formatted for users and SAP reports are data extracts and are not set-up for data integration and manipulation. Instead, Excel is

used to integrate, transform and format reports. FBC is presently assessing the feasibility of implementing an automated solution that will reduce the effort required to generate reports, with expected productivity gains. This automation is expected to be achieved through the use of a data model to aggregate data sources and a reporting tool to allow for self-service.

FBC will be in a better position at next year's Annual Review to provide details of this initiative should it be undertaken, and to provide details of other specific data analytics initiatives undertaken and the benefits achieved.

6. **Robotics Process Automation (RPA):** This is an efficiency initiative using automation software to alleviate repetitive and simple manual tasks. With the rising volume of manual tasks performed for operational work, such as financial transactions or project closeout activities, departments within FBC are challenged. Both the Finance and Engineering departments have experienced an increase in manual activities over several years. Between steps performed multiple times daily, to weekly, monthly or annually, the common theme is a manual and repetitive task with limited decision points.

   In the first phase of RPA implementation, the Company is evaluating opportunities within the Finance and Engineering areas to apply RPA. There are a number of processes being evaluated for RPA with the focus on processes requiring supporting manual activities. The processes vary from creating journal entries, generating third party billing, populating reports, filing documents, and collecting information for budgeting purposes.

   FBC will be in a better position at next year's Annual Review to provide details of this initiative, including the results and benefits achieved.

7. **Paperless Billing Customer Campaigns:** This initiative focuses on working with customers to encourage the switch to paperless billing. In addition to the convenience for customers of receiving their bill electronically and the environmental considerations of less paper and physical transport of the bills, an increased percentage of customers making the switch to paperless billing results in ongoing printing and postage cost savings. At the start of 2021, FBC had approximately 69,000 customers choosing paperless billing as their preferred bill delivery method. Following the success of several internal programs that encouraged employees to highlight this option with customers and including an external social media campaign that resulted in donations to food banks in need, FBC achieved an increase of approximately 8,000 customers choosing this option in 2021. This increase equates to approximately $0.07 million in printing and postage cost savings in 2021 as compared to 2020.[1]

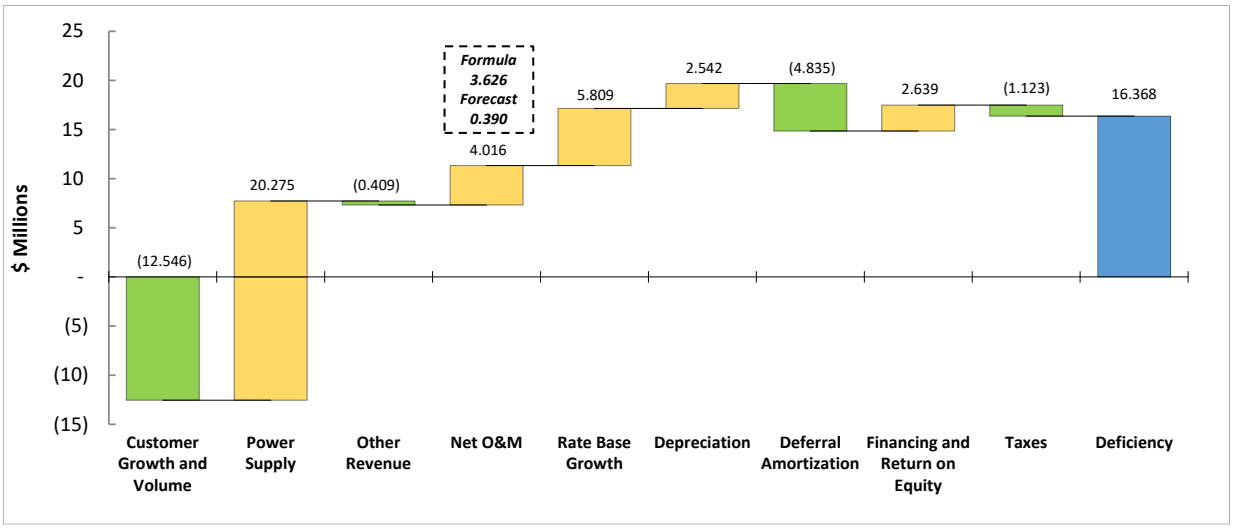
[1] Calculation is a high-level estimate based on the incremental monthly paperless billing growth at an average savings of approximately $1.24 per bill.

1.5 REVENUE REQUIREMENT AND RATE CHANGES FOR 2023

The revenue requirement components set out in the Application result in an effective rate increase of 3.99 percent for 2023 compared to 2022. The effective rate increase results from a revenue deficiency of $16.368 million.

The following chart summarizes the items that contribute to the 2023 revenue deficiency. The chart shows each item that increases the deficiency in yellow and each item that decreases the deficiency in green. The 2023 deficiency of $16.368 million is then the sum of all of the previous bars and is shown at the end of the chart in blue.

Figure 1-1: 2023 Revenue Deficiency ($ millions)



Each of the categories is discussed briefly below.

1.5.1 Customer Growth and Volume Forecast (Section 3)

For 2023, FBC forecasts a net load increase of 170 GWh compared to 2022 Approved, resulting in a decrease in FBC's 2023 revenue deficiency of $12.546 million. The increase in net load is primarily due to increased loads in the industrial classes, followed by smaller increases in the residential, commercial, wholesale, and irrigation classes. FBC's 2023 Forecast revenue at 2022 approved rates is $409.840 million.

1.5.2 Power Supply (Section 4)

FBC forecasts an increase in power supply of $20.275 million in 2023 compared to 2022 Approved. This increase is primarily due to the increase in load, and an increase in PPE under the BC Hydro Power Purchase Agreement (PPA) by approximately $27.240 million. This is offset by reduced market and contracted purchases by approximately $8.776 million.

1.5.3 Other Revenue (Section 5)

Other Revenue is forecast to increase by $0.409 million in 2023 compared to 2022 Approved. The main drivers of this increase are higher Late Payment Charges and the expected annual increases in rates for Apparatus and Facilities Rental, Contract Revenue and Transmission Access Revenue.

1.5.4 Operations and Maintenance (O&M) Expense (Section 6)

FBC establishes the majority of its O&M expense by formula during the MRP term. The O&M formula incorporates a net inflation factor of 4.017 percent, which is inclusive of a productivity improvement factor (X-Factor) of 0.5 percent, and uses a forecast of the change in average customers[2]. The 2023 Formula O&M net of capitalized overhead has increased by $3.626 million[3] when compared to the 2022 Formula O&M. Net O&M forecast outside of the formula is increasing by $0.390 million[4] over 2022 Approved, primarily due to an increase in pension and OPEB expense. Overall, the 2023 increase in total O&M expense net of capitalized overhead is $4.016 million (6.9 percent).

1.5.5 Rate Base Growth and Depreciation (Section 7)

The 2023 rate base is forecast to increase by approximately $92.524 million when compared to the 2022 Approved rate base, resulting in an increase to the 2023 revenue deficiency of $5.809 million. The increase in rate base is primarily the result of the mid-year impact of FBC's 2023 regular capital additions to plant, as well as the full-year impact of FBC's major capital project additions, including the Kelowna Bulk Transformer Additions (KBTA) project, the Corra Linn Dam Spillway Gates Replacement project, and the Playmor Substation Upgrade project, as described in Section 7.1.

The increase in rate base also results in an increase in 2023 depreciation expense by approximately $2.752 million compared to 2022 Approved, which is offset by approximately $0.210 million of CIAC from net additions, resulting in a net increase of $2.542 million in depreciation expense.

1.5.6 Amortization of Deferral Accounts (Section 7 and Section 12)

Amortization of deferral accounts in 2023 decreased by $4.835 million, primarily due to the credit amortization related to the 2020-2024 Flow-through non-rate base deferral account, partially offset by increases in the amortization expense of the DSM deferral account, the BCUC Initiated Inquiry Costs deferral account, and the COVID-19 Customer Recovery Fund deferral account. The credit amortization in the Flow-through deferral account in 2023 is $9.625 million, which is $5.698 million higher than the credit amortization in this account compared to 2022 Approved. As discussed in Section 12.4.2.1, the credit amortization in the Flow-through deferral account is

[2] Modified by 75 percent.
[3] Increase in gross formula O&M of $3.810 million (5.8 percent) compared to 2022 Approved.
[4] Increase in gross forecast O&M of $0.491 million (26.8 percent) compared to 2022 Approved.

primarily due to favourable revenue variances resulting from increased loads from industrial, commercial, wholesale, and residential classes.

1.5.7 Financing and Return on Equity (Section 8)

Financing and Return on Equity (ROE) increased the 2023 deficiency by $2.639 million through changes in financing rates, the ratio of long-term debt versus short-term debt, and changes in rate base.

For 2023, FBC is forecasting a short-term debt rate of 4.24 percent, which is an increase from the 1.51 percent short-term debt rate embedded in the 2022 Approved revenue requirement. Overall, FBC's deficiency is increased by $3.688 million from financing rate changes which is offset by $1.049 million from the ratio change between long-term and short-term debt.

In calculating its 2023 revenue deficiency, FBC has utilized its currently approved capital structure and ROE of 40 percent and 9.15 percent, respectively. As explained in Section 8.1, FBC's ROE is set at a premium of 40 basis points over the benchmark ROE, which is the ROE approved for FEI. FEI is currently participating in the BCUC-initiated GCOC proceeding and has filed evidence on its recommended capital structure and ROE as part of Stage 1 of the proceeding. In Order G-156-21 and accompanying Reasons for Decision, the BCUC found that the effective date to implement a new cost of capital will depend on the timing and progress of the GCOC proceeding. FBC is seeking approval of interim 2023 rates pending the outcome of Stage 1 of the GCOC proceeding as well as a decision on FBC's 2023-2027 DSM Expenditure Plan. When a decision is reached on these proceedings, FBC will update its rate calculations and apply for permanent 2023 rates.

1.5.8 Taxes (Section 9)

FBC's 2023 property taxes are forecast to increase by 2.1 percent or $0.371 million from 2022 Approved. The increase is primarily due to changes in tax rates and increases in assessed values, as well as an increase in grants in-lieu of taxes which are calculated based on a fixed percentage of FBC's revenue.

There has been no change in the income tax rate of 27 percent from 2022. Taxes are forecast to decrease in 2023 by $1.494 million due to higher deductible temporary differences associated with amortization of deferred charges and property, plant and equipment, and lower taxable temporary differences associated with pension and OPEB.

1.6 *SERVICE QUALITY INDICATORS (SECTION 13)*

FBC reports on its 2021 and June 2022 year-to-date SQI results in Section 13. In 2021, for the eight SQIs with benchmarks, six met or were better than the benchmark, with two better than the threshold. For the four SQIs that are informational only, performance in 2021 generally remains at a level consistent with prior years. In 2022 to date, performance for the metrics with benchmarks is trending towards meeting the benchmark or the threshold.

2. FORMULA DRIVERS

2.1 INTRODUCTION AND OVERVIEW

This section provides the calculation of the Inflation Factor (or I-Factor) and Growth Factor used for calculating the 2023 O&M amounts according to the MRP formula.

In the MRP Decision and Order G-166-20, the BCUC approved an I-Factor using the actual CPI-BC and BC-AWE indices from the previous year and a labour weighting based on the most recent completed year of actuals.[5]

The MRP Decision approved the use of a forecast of growth[6] to determine formula O&M and determined that a growth factor multiplier of 75 percent for formula O&M was appropriate.

The Inflation Factor and Growth Factor calculations utilize the above-described inputs and determinations. For 2023, FBC has used July 2020 through June 2022 inflation data for the 2023 revenue requirement calculations, using the Statistics Canada tables included in Appendix A1 of the Application.

2.2 INFLATION FACTOR CALCULATION SUMMARY

In the MRP Decision, the BCUC approved an I-Factor using the actual CPI-BC and BC-AWE indices from the previous year and the actual labour weighting based on the most recent completed year of actuals. FBC uses inflation data from July through June and Statistics Canada Table 18-10-0004-01 for CPI-BC and Table 14-10-0223-01 to determine AWE-BC. The supporting Statistics Canada tables are provided in Appendix A1. The latest available month of April 2022 for AWE-BC has been used as a placeholder, as results to June 2022 have not been released by Statistics Canada. Once results for these periods are available, this placeholder will be replaced with actuals and included in an Evidentiary Update or Compliance Filing.

As shown in Table 2-1 below, the I-Factor has been calculated utilizing actual CPI-BC and AWE-BC data. Applying the actual 2021 labour weighting of 60 percent, the calculation of the 2023 I-Factor is (4.940 percent x 40 percent) + (4.235 percent x 60 percent) = 4.517 percent.

[5] FBC's most recent year of completed actuals is 2021 so that ratio has been used for the 2023 I-Factor calculation.
[6] Forecast of average customers for Formula O&M, including a true-up to actual customers in the following years.

Table 2-1: I-Factor Calculation

Line No.	Date	*Table: 18-10-0004-01* BC CPI index	*Table: 14-10-0223-01* BC AWE $	12 Mth Average CPI index	12 Mth Average AWE $	CPI %	AWE %	Last Completed Year Non Labour %	Last Completed Year Labour %	I-Factor %	MRP Year
1	Jul-2020	132.6	1,093.72								
2	Aug-2020	132.4	1,089.35								
3	Sep-2020	132.5	1,093.75								
4	Oct-2020	132.9	1,095.32								
5	Nov-2020	133.3	1,102.95								
6	Dec-2020	132.8	1,110.36								
7	Jan-2021	133.6	1,113.22								
8	Feb-2021	134.1	1,114.21								
9	Mar-2021	134.9	1,107.66								
10	Apr-2021	135.2	1,112.04								
11	May-2021	135.1	1,118.59								
12	Jun-2021	135.8	1,115.40	133.8	1,105.55						
13	Jul-2021	136.7	1,140.52								
14	Aug-2021	137.0	1,142.40								
15	Sep-2021	137.2	1,139.64								
16	Oct-2021	137.9	1,136.85								
17	Nov-2021	138.1	1,132.25								
18	Dec-2021	138.0	1,134.84								
19	Jan-2022	139.4	1,157.19								
20	Feb-2022	140.4	1,153.88								
21	Mar-2022	143.0	1,161.22								
22	Apr-2022	144.2	1,176.54								
23	May-2022	146.1	1,176.54								
24	Jun-2022	146.5	1,176.54	140.4	1,152.37	4.940%	4.235%	40%	60%	4.517%	2023

2.3 GROWTH FACTOR CALCULATION SUMMARY

As noted above, the BCUC approved the use of a forecast of average customers with a 75 percent modifier to determine formula O&M.

The calculation of average customers used to determine 2023 Formula O&M is summarized in the table below. The growth factor is applied to the unit cost O&M (UCOM), which was calculated based on 2019 average customers of 139,916 (shown on line 21 under year 2020 or line 28 in Table 2-2 below). Starting with this 2019 average customer count, the calculation adds 75 percent of the cumulative average of actual/forecast customer growth during the MRP term from 2020 to 2023 (shown on line 26 in Table 2-2 below) to determine the average customers for rate setting (shown on line 29 of Table 2-2 below).

Table 2-2: Calculation of 2023 Average Customer (AC) Growth Factor

Line No.	Date	Actual 2020	Actual 2021	Projected 2022	Forecast 2023	Total for 2023 Rate Setting	Reference
1	Prior Year Ending Customer Count	141,027	143,714	145,830	148,861		Appendix A2 - Section 3.1 Customers
2							
3	Additions:						
4	January	292	257	226	256		
5	February	174	89	194	266		
6	March	8	123	122	264		
7	April	110	113	178	264		
8	May	173	319	537	255		
9	June	172	116	250	261		
10	July	522	308	255	265		
11	August	129	187	252	262		
12	September	83	136	254	264		
13	October	545	132	255	265		
14	November	234	217	252	262		
15	December	245	119	256	266		
16	Total Additions	2,687	2,116	3,031	3,150		Appendix A2 - Section 3.2 Customer Additions
17	12-month Weighted Average Additions	1,294	1,163	1,587	1,701		
18							
19	Current Year Ending Customer Count	143,714	145,830	148,861	152,011		Line 1 + Line 16; Appendix A2 - Section 3.1 Customers
20							
21	Actual/Projected Prior Year Average Customers	139,916	142,321	144,877	147,417		2020: G-42-21; Sch 3, Line 13; 2021 and 2022: Prior Year Ending, Line 22
22	Average Customers for the Year	142,321	144,877	147,417	150,562		Line 1 + Line 17
23	Change in Average Customers	2,405	2,556	2,540	3,145	**10,646**	Sum of Annual Change in Average Customers on Line 23
24							
25	Growth Factor Multiplier					**75%**	G-166-20
26	Change in Average Customers for Rate Setting Purposes					**7,985**	Line 25 x Line 23
27							
28	Average Customers Used to Determine the Starting UCOM					**139,916**	Line 21, Yr 2020
29	**Average Customer Forecast for Rate Setting**					**147,901**	Line 28 + Line 26
30							
31	2021 Approved Average Customers for Rate Setting		142,473				2021: G-42-21; Sch 3, Line 22
32	2021 Actual Average Customers for Rate Setting		143,637				Line 21(2020) + Sum of Line 23 (2020 & 2021) x 0.75
33	**2021 True Up**		**1,164**				Line 32 - Line 31

2.4 *INFLATION AND GROWTH CALCULATION SUMMARY*

A summary of the factors used to determine formula O&M for 2023 is provided in Table 2-3, including the I-Factor calculated in Section 2.2, the approved X-Factor of 0.5 percent, and the forecast of average customers incorporating the growth factor multiplier determined in Section 2.3.

Table 2-3: Summary of Formula Drivers

Line No.		2023	Reference
1	CPI	4.940%	Table 2-1, Line 24
2	AWE	4.235%	Table 2-1, Line 24
3			
4	Non Labour	40%	Table 2-1, Line 24
5	Labour	60%	Table 2-1, Line 24
6			
7	CPI/AWE Inflation	4.517%	(Line 1 x Line 4) + (Line 2 x Line 5)
8			
9	Productivity Factor	-0.500%	Order G-166-20
10			
11	Net Inflation Factor	4.017%	Line 7 + Line 9
12			
13	Average Customers for Formula O&M purposes	147,901	Table 2-2, Line 29

In summary, the Net Inflation Factor for 2023 is 4.017 percent and formula O&M for 2023 is determined using average customers of 147,901.

3. LOAD FORECAST AND REVENUE AT EXISTING RATES

3.1 *INTRODUCTION AND OVERVIEW*

This section describes FBC's forecast of gross system load. The gross system load is a combination of residential, commercial, wholesale, industrial, lighting and irrigation loads, system losses and company use. The forecast of gross system load includes the impacts of forecast load savings which include Demand Side Management (DSM) savings. These savings are further explained in Section 3.3 – Demand Side Management Savings.

FBC is forecasting an increase in consumption in the 2023 Forecast (2023F) compared to the 2022 Approved. The 2023F gross load is forecast to be approximately 3,775 GWh, which is a 184 GWh increase compared to the 2022 Approved gross load. The increase in 2023F is due to increased loads in the industrial, commercial, wholesale, residential and irrigation classes. Based on the 2022 Approved rates for each customer class, FBC's 2023 revenue forecast is $409.840 million.

FBC has provided further information supporting its load forecast in Appendix A of the Application.

3.2 *OVERVIEW OF FORECAST METHODS*

Consistent with the forecasting method followed by FBC in previous years, the load forecast relies on the following components:

- the residential and commercial customer count forecast;
- the residential use per customer (UPC) forecast;
- the commercial, lighting and irrigation load forecast; and
- the industrial and wholesale survey forecast.

The load forecast for residential customers is based on forecasts for the number of customers and UPC rates. Specifically, the UPC forecast is multiplied by the corresponding forecast of the number of annual average customers to derive the residential load forecast. The commercial load forecast is based on a regression against the Conference Board of Canada (CBOC) Gross Domestic Product (GDP) forecast, the lighting forecast uses the prior year's actual load, and the irrigation forecast uses a five-year historical average. Wholesale and industrial forecasts are primarily based on customer-specific survey results.

More detail on FBC's forecasting methods can be found in Appendix A of this filing.

The following sections set out the results of the load forecast. In the figures provided in the load forecast sections, the following three time periods are shown:

- Actual Years: Actual years are those for which actual data exists for the full calendar year. For this Annual Review the latest calendar year for which full actual data exists is the 2021 calendar year.
- Seed Year: The Seed Year is the year prior to the first forecast year. The Seed Year is forecast based on the latest years of actual data available,[7] and will be different than the original forecast for that year in the previous filing. For example, for this Application the Seed Year is 2022 (2022S) and the Seed Year forecast is based on the latest actual years, including 2021. As such, the 2022 Seed Year forecast in this Application will differ from the 2022 Forecast presented in the Annual Review for 2022 Rates, for which 2021 actual data was not available.
- Forecast Year: This is the year or years for which the forecast is being developed. This can be one year (in the case of the Annual Review) or a range of two or more years depending on the filing. In this Application, the forecast year is 2023 (2023F).
- Also included in the figures in this section is the prior year's forecast (shown as the green Approved lines in the figures below), as presented in the Annual Review for 2022 Rates.

FBC acquired the utility assets and customers of the City of Kelowna's electric utility effective March 31, 2013, resulting in an increase in direct customers and changes in the composition of customers and sales load by class, which are reflected in the data and figures in this section.

3.3 *DEMAND SIDE MANAGEMENT SAVINGS*

FBC forecasts the DSM savings that are incremental to the DSM savings that are already embedded in historical loads up to and including 2021.

The DSM savings forecast is deducted from the before-savings forecast for all customer classes. All forecast values in the sections below are shown after being reduced by DSM savings unless explicitly stated otherwise.

The forecast incremental DSM savings for 2023 are summarized in Table 3-1 below, and are the forecast savings incremental to the savings embedded in the historical loads. Historical DSM savings can be found in Appendix A2.

[7] FBC's load forecast is developed using only complete years of historical data. FBC requires the complete year of load data in order to validate it, including the review of and potential adjustments to unbilled energy. For this reason, partial year data is not used in forecasting.

Table 3-1: Forecast Incremental 2023 DSM Savings (GWh)

Line No.	Description	DSM 2023
1	Residential	(8.9)
2	Commercial	(22.6)
3	Wholesale	(7.7)
4	Industrial	(16.2)
5	Lighting	(0.3)
6	Irrigation	(0.2)
7	Net	(55.9)
8	Losses	(4.6)
9	Gross Load	(60.5)

3.4 *LOAD FORECAST*

FBC's total load consists of the weather normalized residential, commercial and wholesale load and the actual industrial, lighting and irrigation load. In aggregate, the absolute load forecast variance in 2021 was 0.2 percent. As shown in Figure 3-1 below, the total load, net of losses, is forecast to be 3,476 GWh in 2023F, which is 3 GWh more than 2022S and an increase of 170 GWh from 2022 Approved.

Figure 3-1: Total Net Load (GWh)

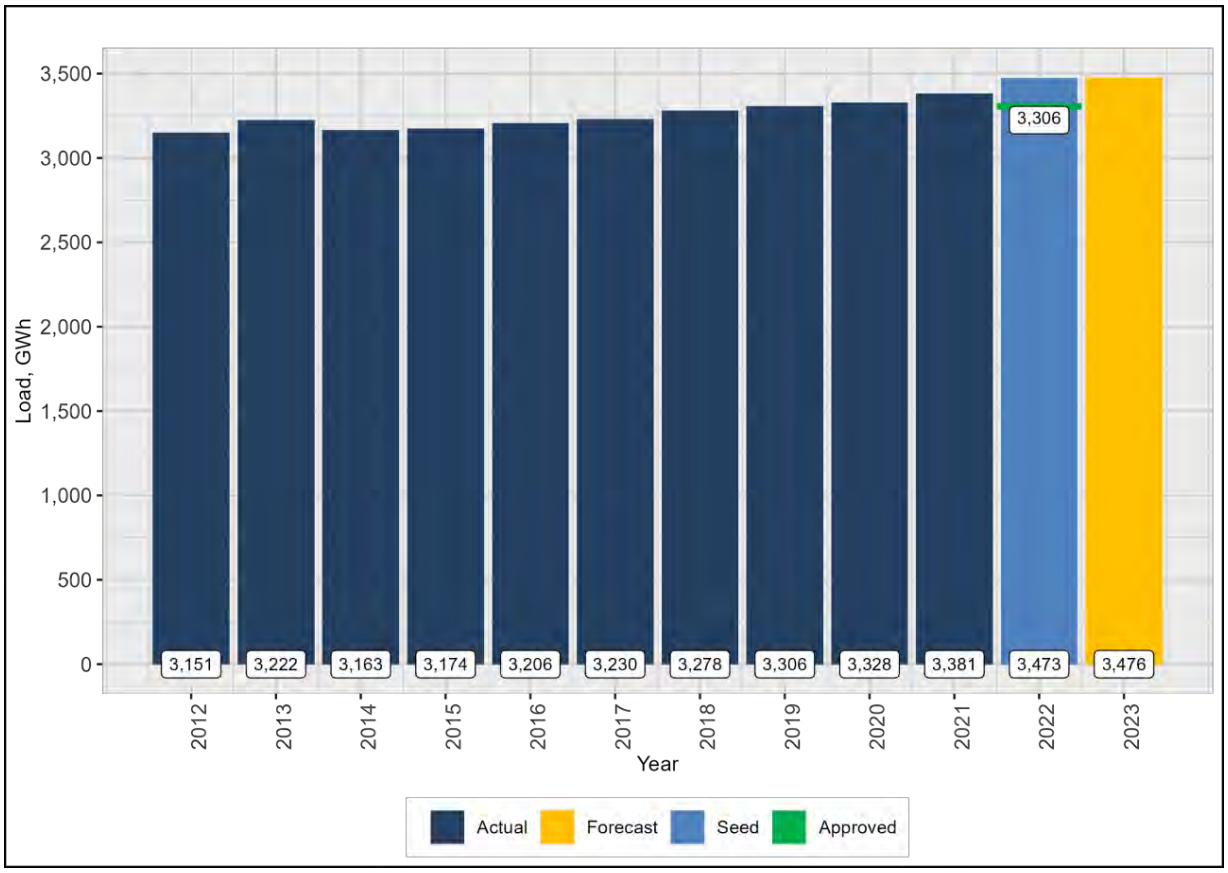


Table 3-2 below shows the normalized after-savings gross load by customer class as well as the system peak. For 2023F, the residential customer class is forecast to account for 34 percent of the normalized after-savings gross load.

Table 3-2: Normalized After-Savings Gross Load and System Peak

Line No.	Description	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022S	2023F
	Energy (GWh)												
1	Residential	1,229	1,353	1,296	1,298	1,296	1,320	1,313	1,266	1,347	1,330	1,304	1,301
2	Commercial	681	788	863	853	905	915	926	932	922	960	962	973
3	Wholesale	899	675	567	580	574	574	585	566	569	566	579	578
4	Industrial	291	352	381	380	373	363	403	495	441	472	579	575
5	Lighting	13.5	13.5	15.6	15.9	15.9	15.9	13.2	11.0	10.8	9.7	9.5	9.4
6	Irrigation	38.0	39.7	40.0	46.0	42.1	41.9	39.0	36.0	37.3	43.6	39.5	39.4
7	Net Load	3,151	3,222	3,163	3,174	3,206	3,230	3,278	3,306	3,328	3,381	3,473	3,476
8	Losses & Company Use	271	278	270	272	274	282	285	287	288	295	299	299
9	Gross Load	3,422	3,500	3,433	3,446	3,480	3,512	3,564	3,592	3,616	3,677	3,771	3,775
10													
11	System Peak (MW)												
12	Winter Peak	723	698	693	685	755	714	682	732	731	685	782	786
13	Summer Peak	589	600	620	611	593	605	631	639	666	653	678	684

The residential, commercial, wholesale, industrial, lighting, irrigation, loss load and the winter and summer peak demand forecasts are provided separately in the following subsections.

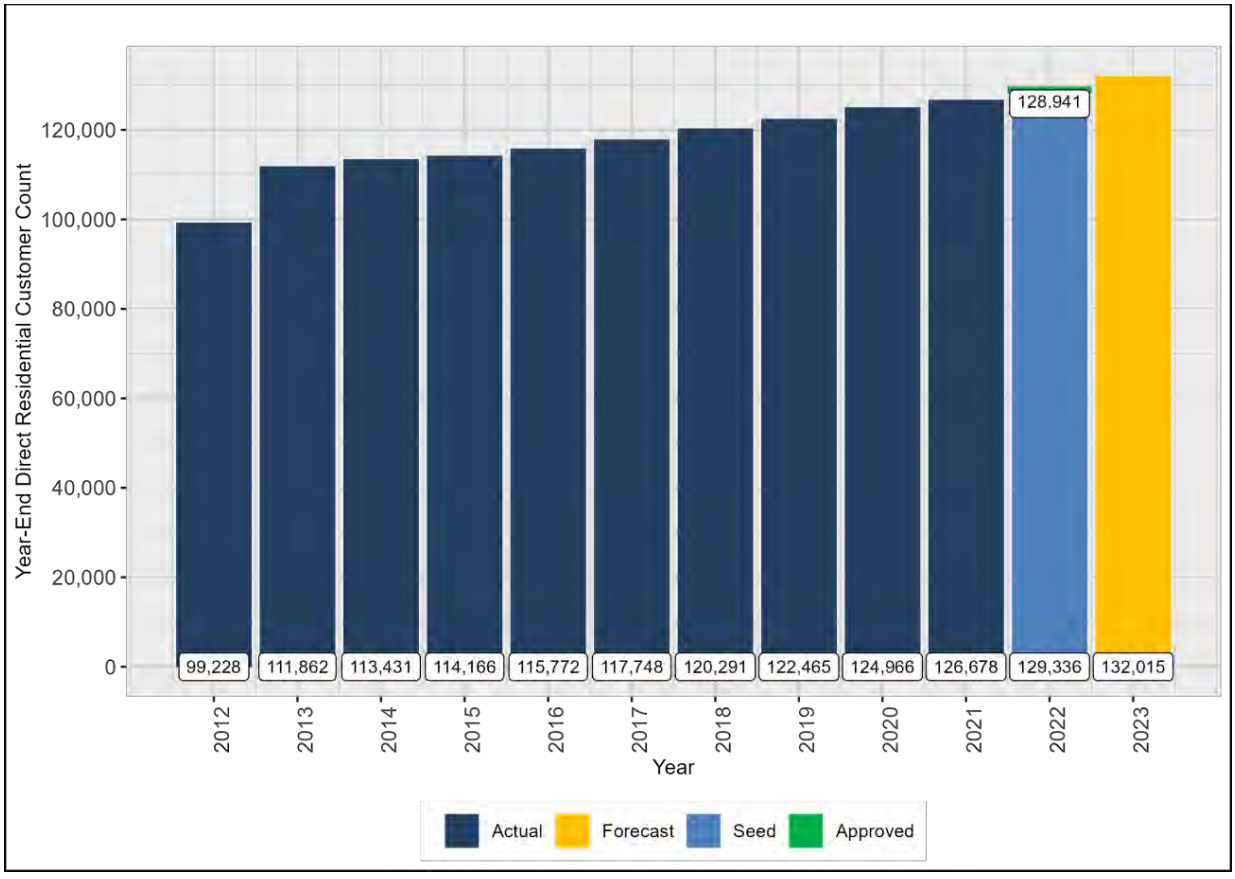
3.4.1 Residential

3.4.1.1 Residential Customers

Forecast residential customer counts are determined by a regression of the year-end customer accounts against population in the FBC direct service area. The population forecast for the FBC service area is provided by a BC Statistics report produced for FBC.

Figure 3-2 shows the year-end residential customer count for FBC.

Figure 3-2: Year-End Direct Residential Customer Count

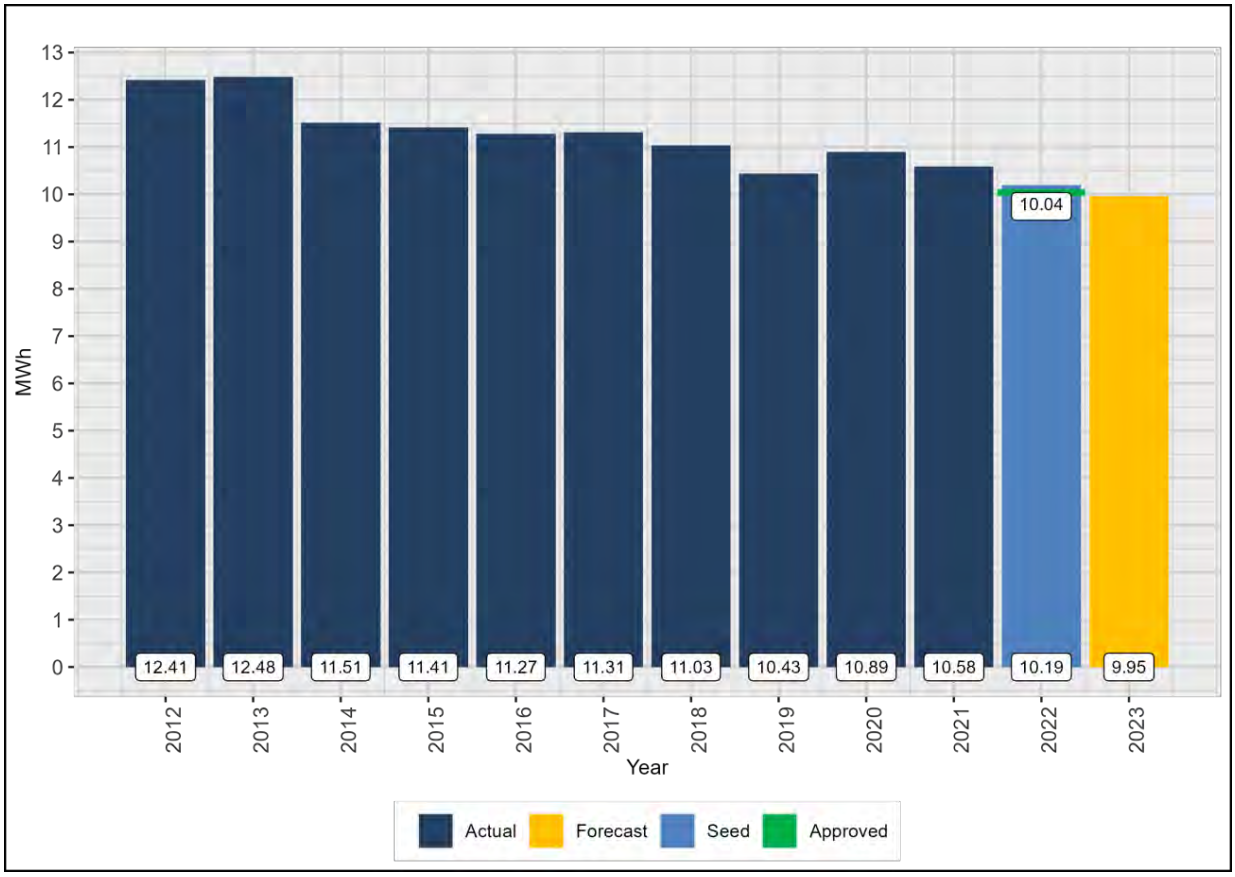


3.4.1.2 Residential UPC

Normalized historical UPCs are obtained by dividing the weather-normalized residential load by the average customer count in each year. The before-savings UPC is forecast by applying a 10-year trend to the normalized historical UPCs. The before-savings UPC forecast is then multiplied by the forecast average customer count to derive the before-savings load forecast. DSM savings, which are incremental to the savings embedded in the historical data to 2021, are then deducted from the before-savings load forecast to determine the after-savings load forecast. The after-savings UPC forecast is then calculated by dividing the after-savings load forecast by the average

customer count. As shown in Figure 3-3 below, the residential after-savings UPC is forecast to decrease by 0.24 MWh in 2023F from 2022S and decrease by 0.09 MWh from 2022 Approved.

Figure 3-3: Normalized After-Savings Residential UPC (MWh)

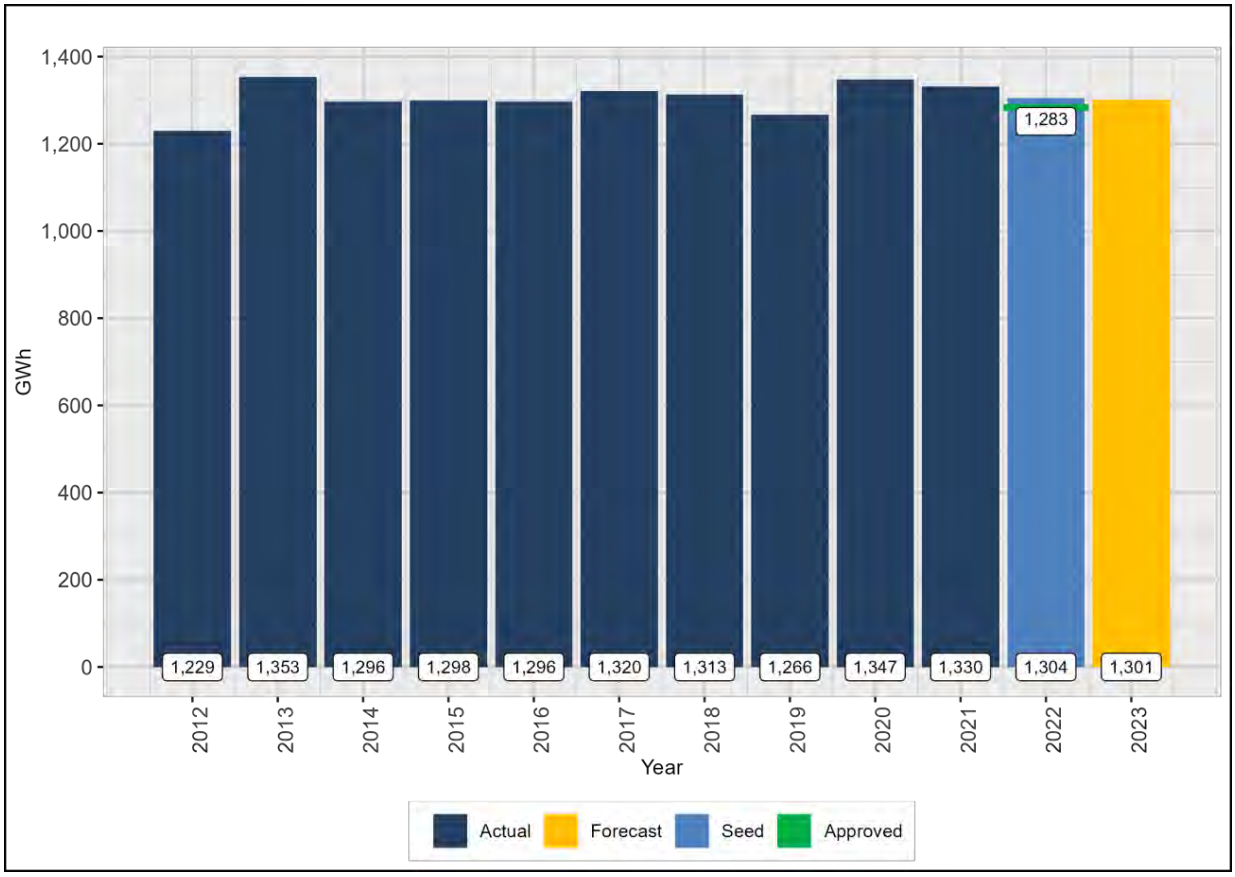


3.4.1.3 Residential Load

Consistent with past practice, the total before-savings load for the residential class is the product of the average annual residential customer count multiplied by the residential UPC. The after-savings load is produced by taking the before-savings load and then subtracting DSM savings.

As shown in Figure 3-4 below, residential after-DSM savings load is forecast to decrease by 3 GWh in 2023F from 2022S and increase by 18 GWh from 2022 Approved levels.

Figure 3-4: Normalized After-Savings Residential Load (GWh)

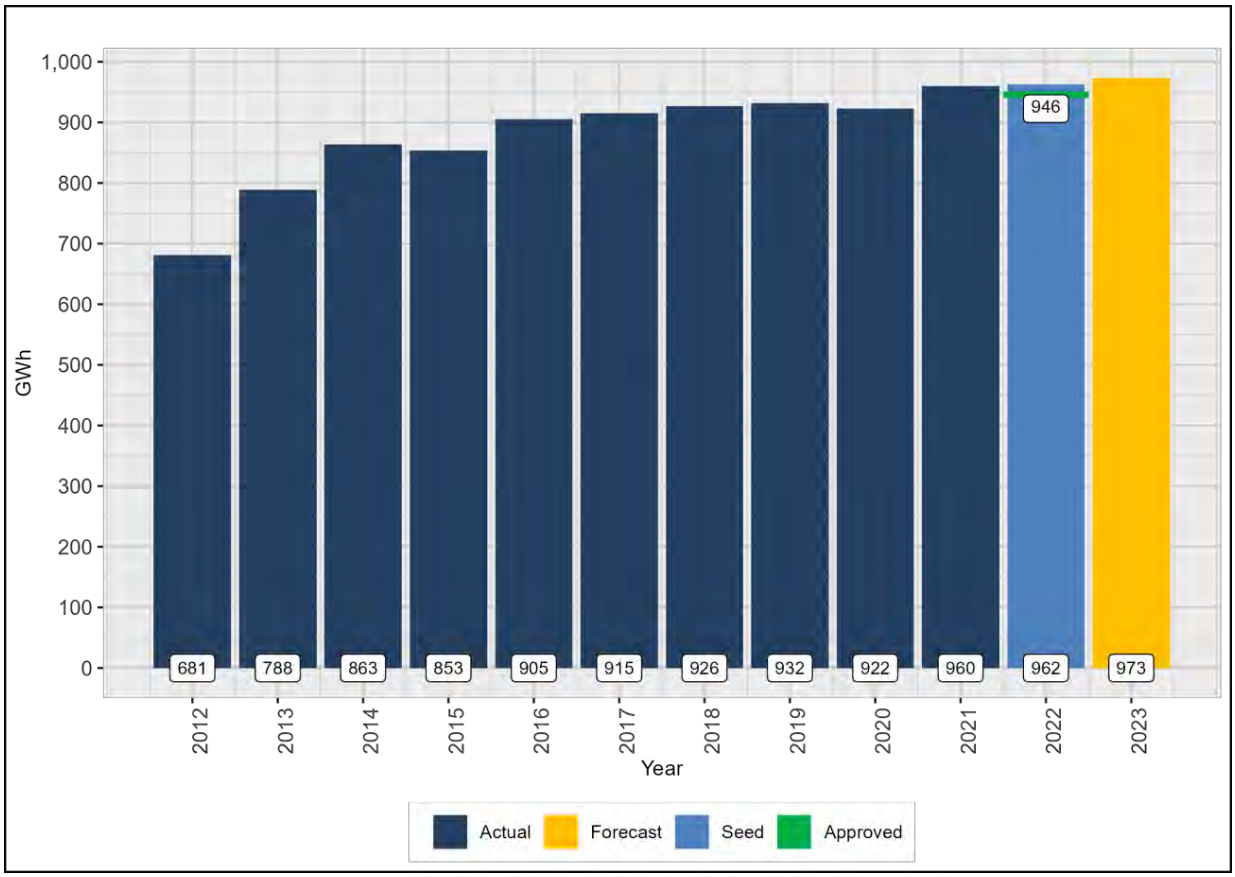


3.4.2 Commercial

3.4.2.1 Commercial Load

The commercial class is forecast based on a regression of load on the provincial GDP forecast obtained from the CBOC. The load for Electric Vehicle Direct Current Fast Chargers (EV DCFC) serviced by FBC are then added to 2022S and 2023F and account for less than a 1 GWh increase in both 2022S and 2023F. As shown in Figure 3-5 below, commercial after-savings load is forecast to increase by 11 GWh in 2023F from 2022S and increase by 27 GWh in 2023F from 2022 Approved.

Figure 3-5: After-Savings Commercial Load (GWh)



3.4.3 Wholesale

FBC sells wholesale power to municipalities for service to certain customers within its service territory that own and operate their own electrical distribution systems, and to BC Hydro. The wholesale customers' load composition is a combination of residential, commercial, industrial and lighting.

Consistent with past practice, the wholesale class is forecast using survey information from each of the individual wholesale customers, as the individual wholesale customers are best able to forecast their future load growth. For 2023, all but one of the wholesale customers responded with their load forecast projections.

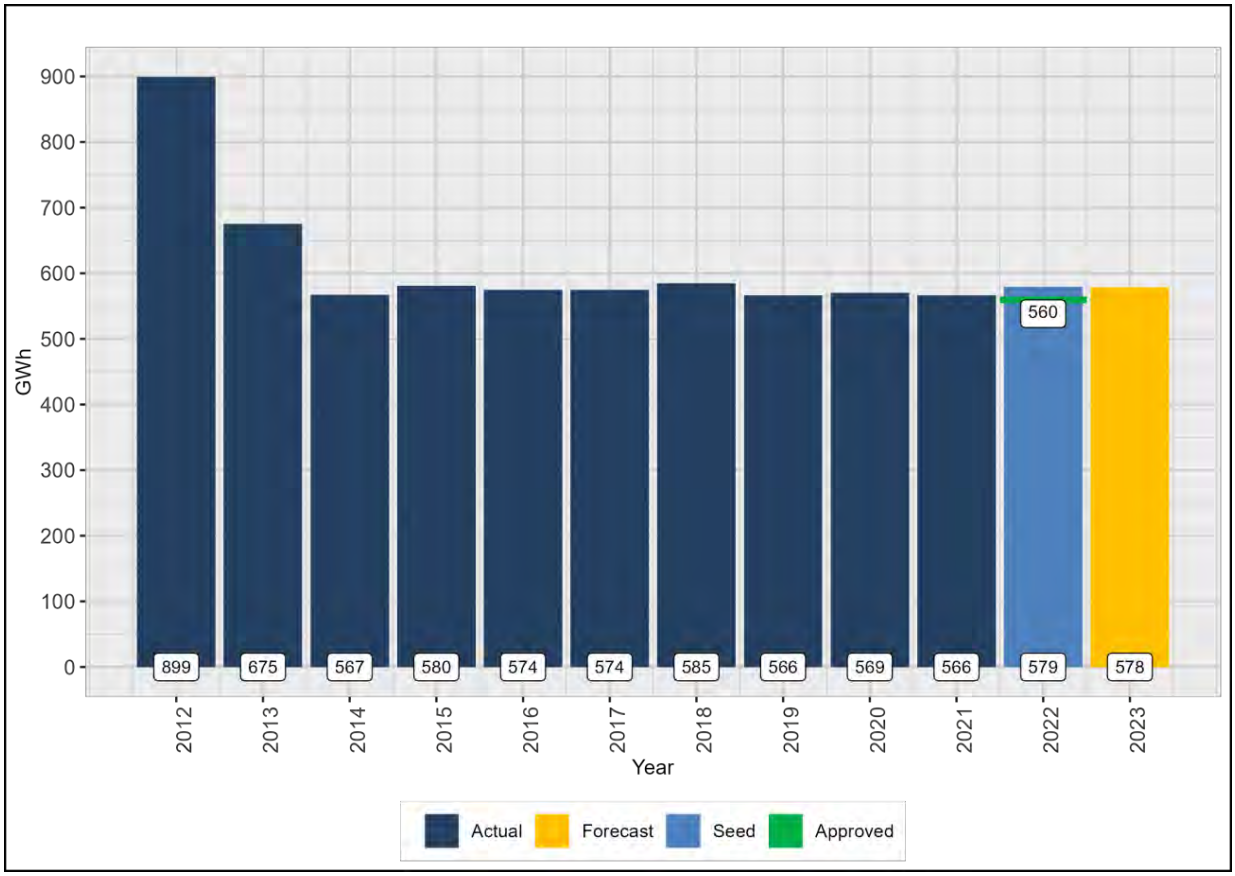
In the Annual Review for 2022 Rates Decision, the BCUC Panel directed FBC "to provide any efforts it has undertaken to improve the accuracy of its forecasts of wholesale customer load in the 2023 Annual Review, including the results of such efforts."[8] The BCUC Panel further requested that FBC work more closely with wholesale customers to develop more accurate forecasts. As such, in April of this year, FBC met with the City of Penticton, the District of

[8] FBC Annual Review for 2022 Rates Decision and Order G-374-21, p. 32.

Summerland and the City of Nelson to discuss load forecast methods, techniques and tools, as well as each City's/District's individual load forecasts. Both FBC and the Cities/District found the workshops to be informative and productive, and FBC intends to continue to conduct these workshops on an annual basis in the future.

As shown in Figure 3-6 below, after-savings wholesale load is forecast to decrease by 1 GWh in 2023F from 2022S and increase by 18 GWh in 2023F from 2022 Approved.

Figure 3-6: Normalized After-Savings Wholesale Load (GWh)



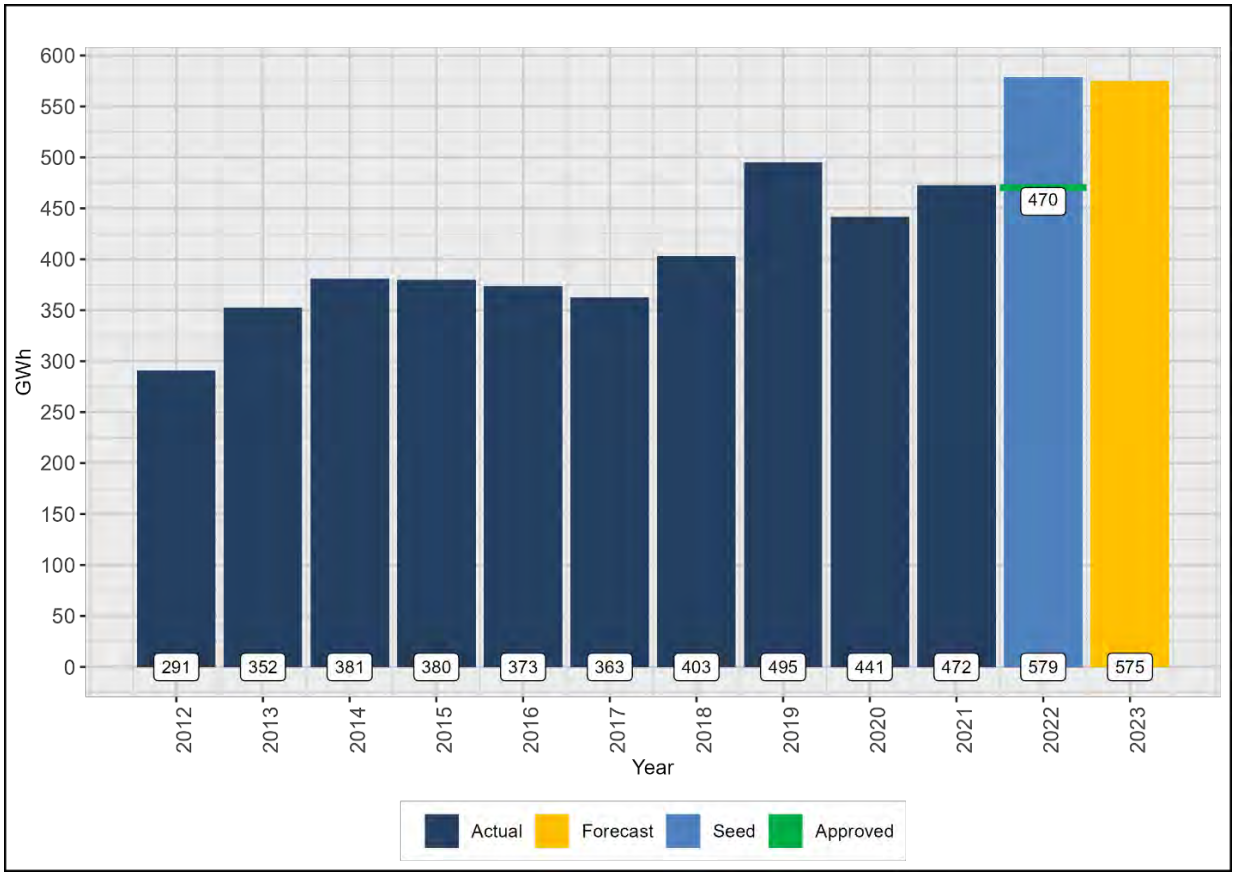
3.4.4 Industrial

Consistent with past practice, the industrial forecast is determined through a combination of customer load surveys and, when not available, escalation of the most recent annual loads by the corresponding provincial GDP growth rates for individual industries.

FBC sends all existing industrial customers a load survey that requests the customer's anticipated use for the next five years. A survey is used because individual industrial customers have the best understanding of what their future load will be. This year FBC received a response from 81 percent (34 of 42) of the surveys sent out. The responding customers represent approximately 90 percent of the total industrial load.

As shown in Figure 3-7 below, after-savings industrial load is forecast to decrease by 4 GWh in 2023F when compared to 2022S and increase by 105 GWh in 2023F compared to 2022 Approved. The increased forecast in 2022S and 2023F compared to 2022 Approved is primarily due to projected increases in data centre loads.

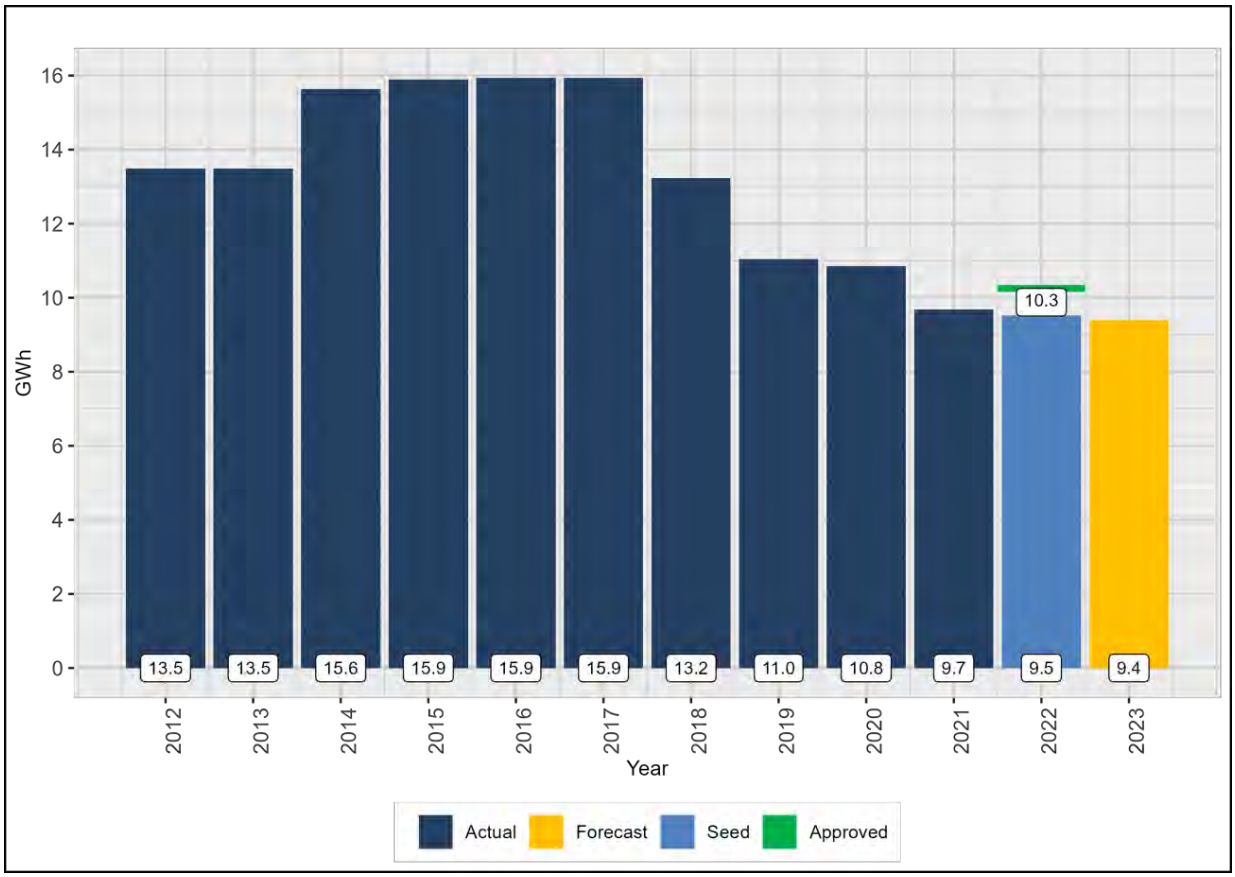
Figure 3-7: After-Savings Industrial Load (GWh)



3.4.5 Lighting

Due to the implementation of LED streetlights, the lighting load has seen declines for the past four years. FBC used the 2021 Actuals as the forecast for this load and then reduced it by DSM savings. As shown in Figure 3-8 below, after-savings lighting load is forecast to decrease by 0.1 GWh in 2023F from 2022S and decrease by 0.9 GWh when compared to 2022 Approved.

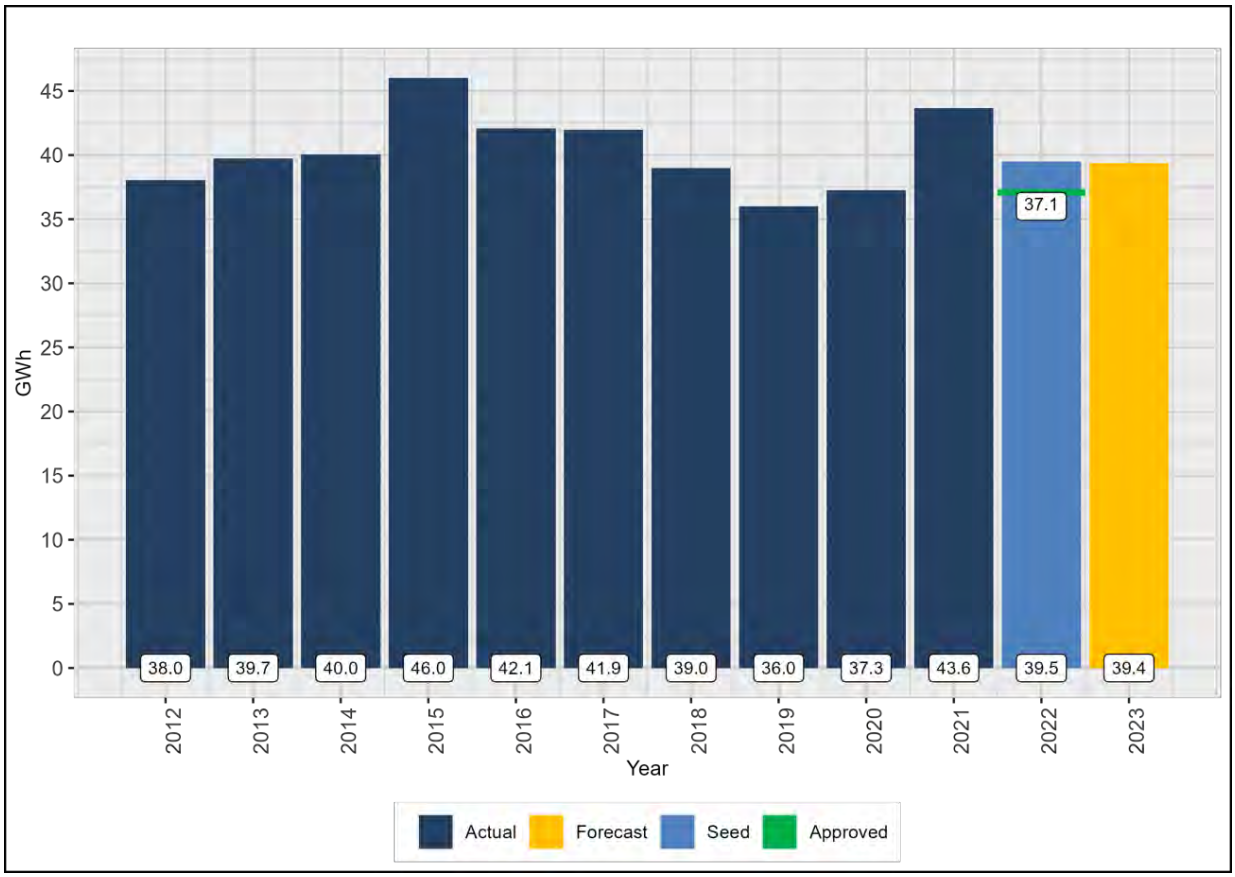
Figure 3-8: After-Savings Lighting Load (GWh)



3.4.6 Irrigation

Due to the variability in the load in the recent historical data, FBC used a five-year average as the forecast for the irrigation load. As shown in Figure 3-9 below, after-savings irrigation load is forecast to decrease 0.1 GWh from 2022S to 2023F and increase by 2.3 GWh in 2023F when compared to 2022 Approved.

Figure 3-9: After-Savings Irrigation Load (GWh)



3.4.7 Losses and Company Use

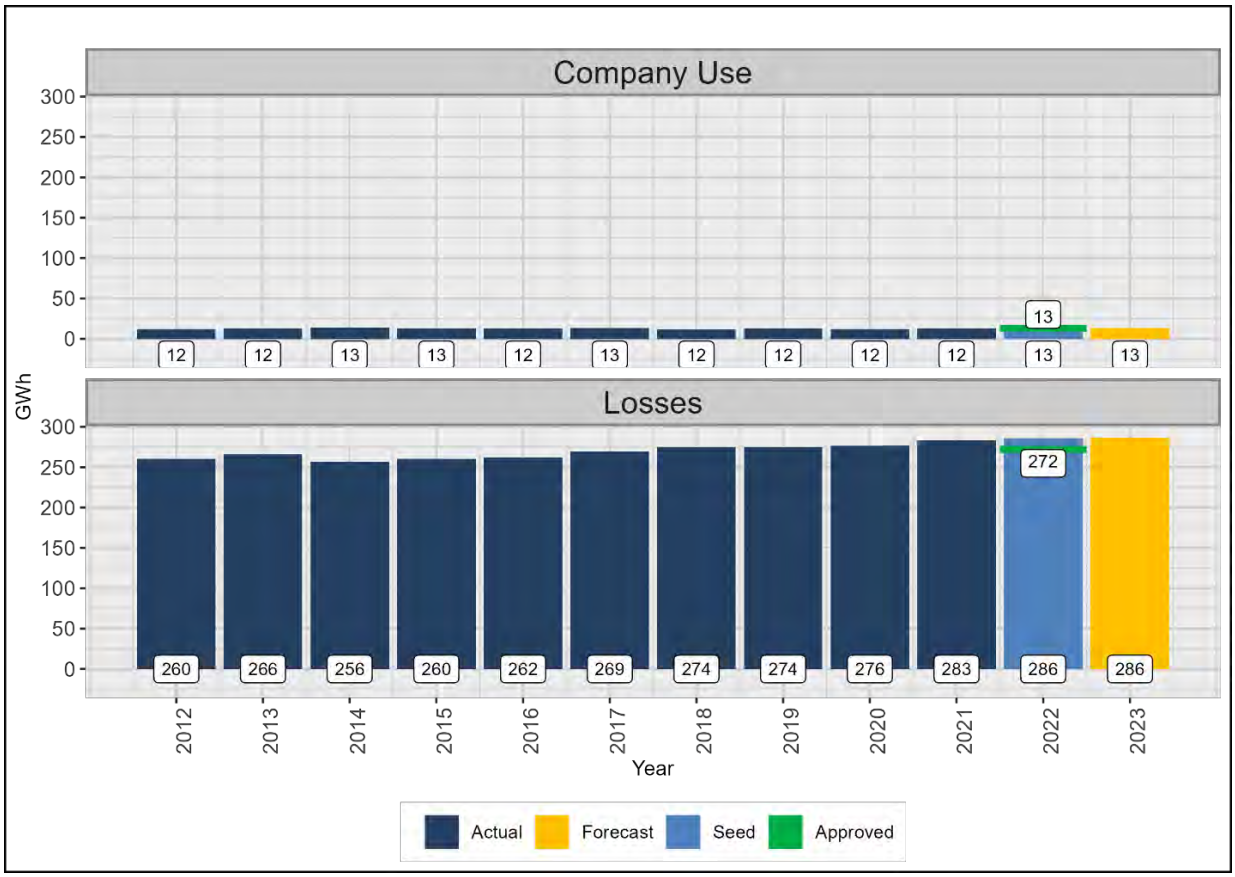
FBC conducted a Losses Study in 2019[9] and, consistent with that study, has assumed a loss rate of 7.6 percent of gross load (excluding company use). System losses consist of:

- Losses in the transmission and distribution system;
- Losses due to wheeling through the BC Hydro system; and
- Unaccounted-for load (meter inaccuracies and theft).

As shown in Figure 3-10 below, after-savings load losses are forecast to remain constant in 2023F because the gross load is forecast to be relatively stable when compared to 2022S. When compared to 2022 Approved, the 2023F after-savings load losses are forecast to increase by 14 GWh due to increased load. FBC has separated company use in the graph below, which is forecast at 13 GWh per year in 2023F, consistent with 2022S.

[9] MRP Application, Exhibit B-1-1, Appendix B3.

Figure 3-10: Normalized After-Savings Load Losses (GWh)



3.4.8 Peak Demand

The peak demand forecast is produced using the 10-year average of historical peaks, including peaks from the June 2021 "heat dome" event. The historical peak data is escalated by the gross load growth rate before it is averaged to account for the growth of demand on the FBC system.

Normalized after-savings historical winter and summer peaks are shown below along with 2022S and 2023F. The peaks shown below are seasonal, where the winter peak can fall in either November or December of the current year or January and February of the following year, while the summer peak falls in June, July or August of the current year.

Figure 3-11: After-Savings Winter Peaks (MW)

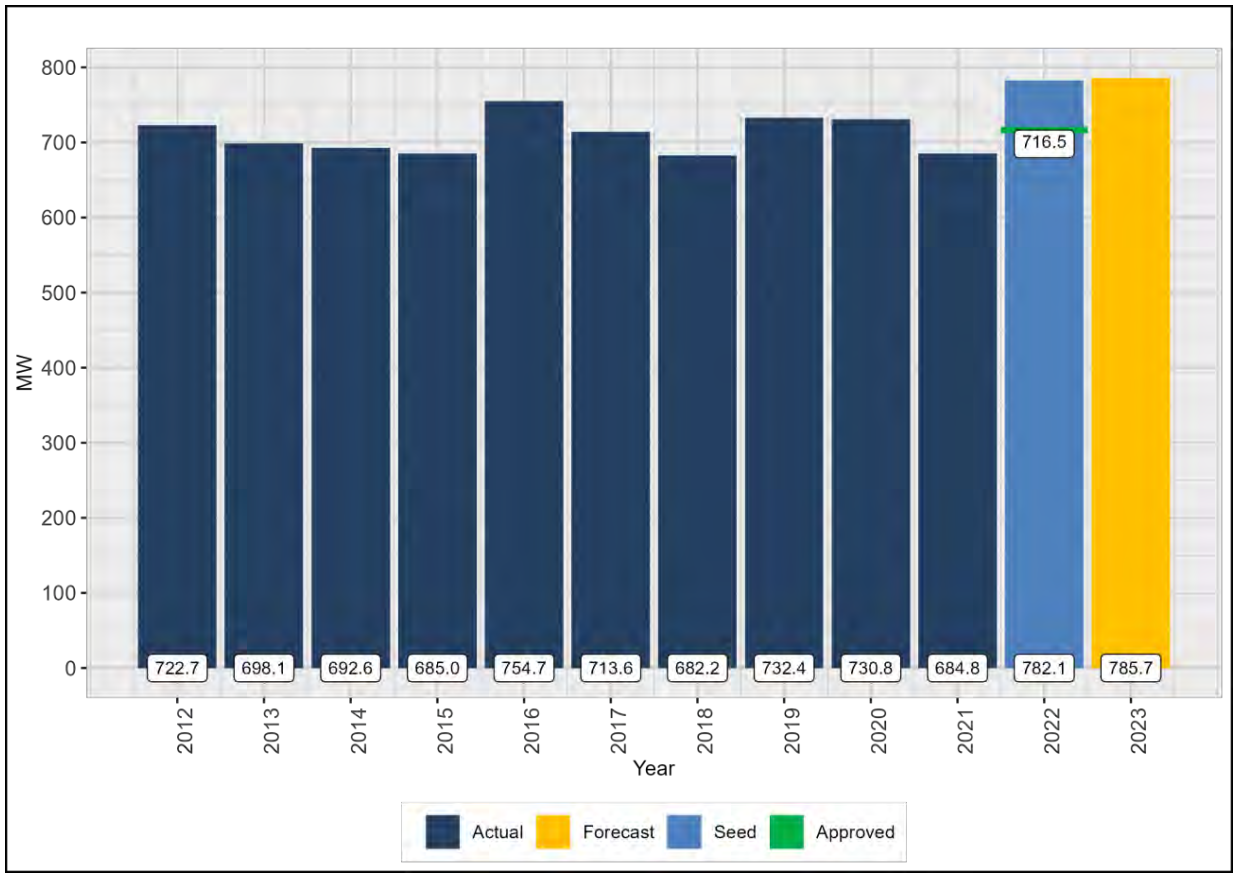
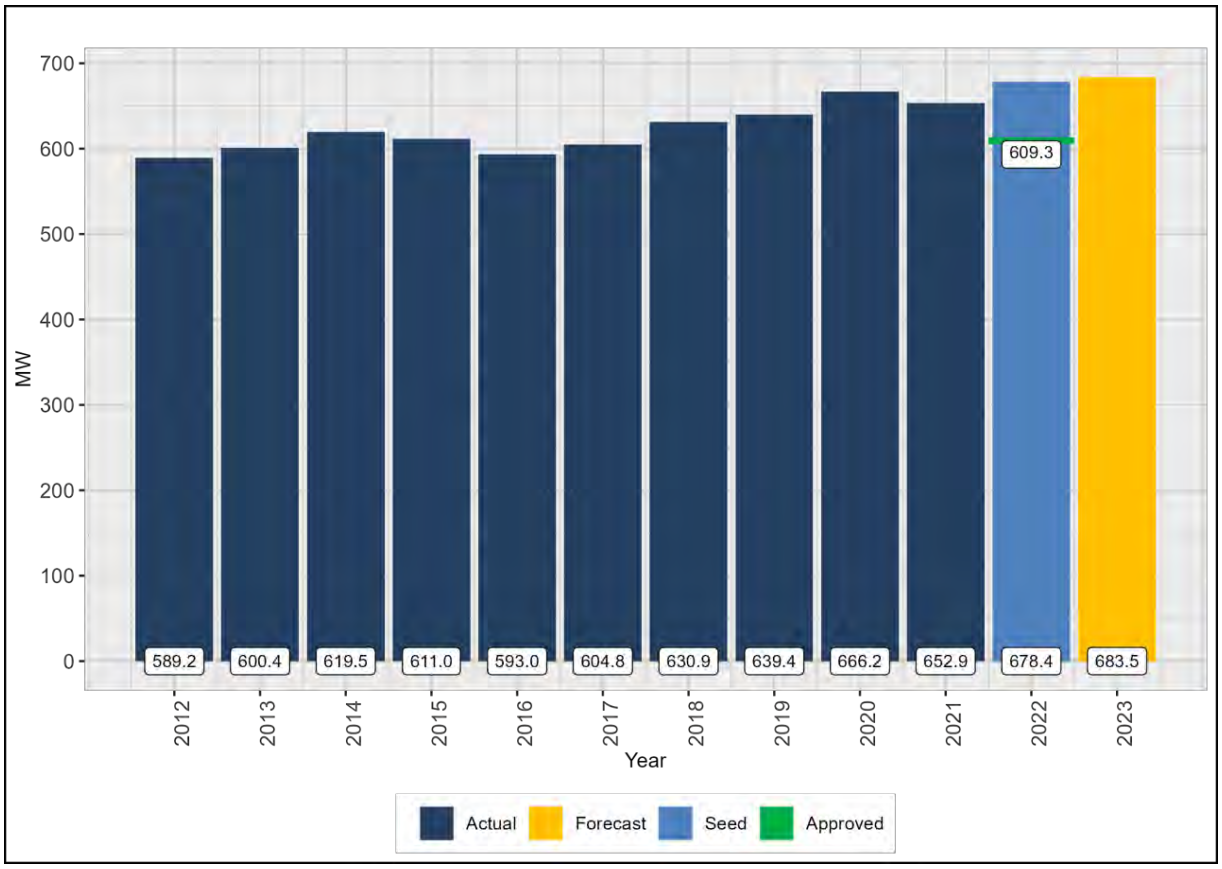


Figure 3-12: After-Savings Summer Peaks (MW)



3.5 *CUSTOMER FORECAST*

Table 3-3 shows the actual and forecast year-end customer count by rate class. The residential and commercial customer counts are forecast using the methods described in Sections 3.4.1 and 3.4.2, respectively. Industrial customers are forecast based on information on expected new loads provided by key account managers. The lighting customer forecast is prepared using a three-year regression of year-end customer counts. Wholesale and irrigation customer counts are assumed to remain at 2021 levels.

Overall, for 2023F, FBC is forecasting customer growth of 2.1 percent compared to 2022S and growth of 2.4 percent compared to 2022 Approved.

Table 3-3: Year-End Direct Customer Count

Line No.	Description	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022S	2023F
1	Residential	99,228	111,862	113,431	114,166	115,772	117,748	120,291	122,465	124,966	126,678	129,336	132,015
2	Commercial	11,811	13,662	14,363	14,976	15,073	15,398	15,678	15,956	16,165	16,594	16,995	17,496
3	Wholesale	7	6	6	6	6	6	6	6	6	6	6	6
4	Industrial	39	47	49	50	50	50	52	51	43	42	42	42
5	Lighting	1,739	1,644	1,620	1,590	1,559	1,511	1,482	1,467	1,443	1,407	1,379	1,349
6	Irrigation	1,091	1,097	1,103	1,095	1,090	1,080	1,078	1,082	1,091	1,103	1,103	1,103
7	**Total**	113,915	128,318	130,572	131,883	133,550	135,793	138,587	141,027	143,714	145,830	148,861	152,011

3.6 REVENUE FORECAST

The forecast of revenues has been developed by applying approved 2022 rates to the forecast billing determinants for each customer class.

Table 3-4 below summarizes the 2022 Approved, 2022 Projected and 2023 Forecast sales revenue.

Table 3-4: Forecast Sales Revenue at Approved Rates ($ millions)[10]

Line No.	Description	Approved 2022	Projected 2022	Forecast 2023
1	Residential	$ 195.058	$ 200.837	$ 197.962
2	Commercial	104.380	107.153	106.230
3	Wholesale	51.255	53.722	52.031
4	Industrial	40.804	46.764	47.856
5	Lighting	2.411	2.266	2.207
6	Irrigation	3.386	3.550	3.554
7	Total	$ 397.294	$ 414.292	$ 409.840

When comparing the 2022 Approved to 2022 Projected there is an increase in revenue of $16.998 million, the majority of which is due to increased residential and industrial loads.

The 2023 Forecast revenue is $12.546 million higher than 2022 Approved, primarily due to an increase in the industrial load, followed by small increases in the residential, commercial, and wholesale loads. These increases are slightly offset by a decrease in the lighting load resulting from the continued conversion to LED streetlights in the FBC service territory.

Variances between the revenue forecast in this section and the actual revenues realized are captured in the Flow-through deferral account.

3.7 SUMMARY

The normalized after-savings gross load forecast for 2023F is 3,775 GWh. Based on net load of 3,476 GWh at the approved 2022 rates, FBC's 2023 revenue forecast is $409.840 million. When comparing 2023F to 2022 Approved, there is an increase in net load of 170 GWh. The net load increase in 2023F is due to increased loads in the industrial, commercial, wholesale residential and irrigation classes.

[10] The commercial sales revenue includes the revenues under RS 96 EV DCFC Stations. Please refer to Section 5.8 for further detail on EV DCFC station costs and revenues.

4. POWER SUPPLY

4.1 INTRODUCTION AND OVERVIEW

This section includes a review of the 2022 Projected and 2023 Forecast power purchase expense (PPE), wheeling expense and water fees. Collectively, the PPE, wheeling expense and water fees are referred to as the power supply cost.

As shown in Table 4-1 below, the 2023 Forecast power supply cost of $182.105 million represents an increase of 12.5 percent or $20.275 million compared to the 2022 Approved cost of $161.830 million. The increase in 2023 Forecast power supply cost is mainly due to increases in PPE, however, wheeling expense has increased as well. The 2023 Forecast PPE has increased as a result of increased gross load and a reduction in wholesale market purchases, which has resulted in a correspondingly greater reliance on energy supplied under BC Hydro Rate Schedule (RS) 3808. 2023 Forecast wheeling expense has increased as a result of both rates and usage. The 2023 Forecast water fee expense has decreased compared to 2022 Approved as a result of decreased usage.

Any variances between forecast and actual power supply costs are recorded in the Flow-through deferral account and returned to or recovered from customers in the subsequent year.

Table 4-1: Power Supply Cost ($ millions)

Line No.	Description	Approved 2022	Projected 2022	Forecast 2023
1	Power Purchase Expense	$ 143.779	$ 153.164	$ 163.575
2	Wheeling Expense	6.093	6.330	6.987
3	Water Fees	11.958	11.916	11.543
4	Total Power Supply Cost	$ 161.830	$ 171.409	$ 182.105
5				
6	Gross Load (GWh)	3,591	3,786	3,775

4.2 SUMMARY OF POWER SUPPLY RESOURCES

FBC uses a combination of Company-owned generation entitlements, firm contracted supply, and market purchases to meet its load requirements. The Company's firm resources consist of:

1. Canal Plant Agreement (CPA) Entitlements associated with the generation facilities owned by FBC. The costs associated with FBC-owned generation are not included in the power purchase estimates, except for the Balancing Pool adjustments, which account for year-to-year timing differences in the entitlement energy storage under the CPA;
2. The Brilliant Power Purchase Agreement (BPPA), a 125 MW contract (Order E-7-96), and an amendment to the BPPA which reflects the purchase of 20 MW of Brilliant Upgrade

power (Letter L-57-00), and the 5 MW Brilliant Tailrace Capacity agreement (Order E-17-01);

3. A power purchase agreement (PPA) with BC Hydro (a 200 MW contract) under BC Hydro RS 3808 (Order G-60-14);
4. The Waneta Expansion Capacity Purchase Agreement (WAX CAPA), which is a 40-year purchase agreement with the Waneta Expansion Limited Partnership for capacity entitlements under the CPA (Orders E-29-10 and E-15-12);
5. A number of small Independent Power Producer (IPP) contracts; and
6. A number of market purchase arrangements.

4.3 *PORTFOLIO OPTIMIZATION*

The primary objectives of FBC's power supply portfolio planning are to ensure that the Company has sufficient firm resources to meet expected load requirements, to ensure the availability of cost-effective reliable power for FBC's customers, to prudently manage exposure to the cost and availability of market power supplies, and to optimize the value of any surplus resources that are not needed to meet load requirements.

The Company currently has long-term, firm resources from which it can supply all of its 2023 forecast annual energy requirements, and most of its forecast capacity requirements with the exception of a small number of hours during June and July. These forecast capacity gaps result from the Company's updated, increased load forecast. As mentioned in previous Annual Reviews, the nature of FBC's contracted resources, in particular the BC Hydro PPA, provides the Company some flexibility to participate in the market when conditions are favourable to mitigate the cost of holding those firm resources. However, in contrast to recent years, the regional electricity market has experienced a step change over the past year due to several factors that include resource adequacy concerns, increased natural gas prices, and increased severe weather events. This change in the market price environment has resulted in little opportunity to displace PPA purchases on a forward basis. Furthermore, although FBC's load requirements are forecast to grow over time, the amount of capacity provided under the WAX CAPA is currently greater than FBC's capacity requirements in most months, and FBC sells the surplus capacity to mitigate power purchase expense. FBC has contracted to release a 50 MW block of capacity purchased under the WAX CAPA to BC Hydro under the Residual Capacity Agreement (RCA), which was approved by Order G-161-14. The remaining surplus WAX CAPA will be sold to Powerex Corp. (Powerex) on a day-ahead basis, if and when it is not required to meet FBC load requirements. These sales are made under the Capacity and Energy Purchase and Sale Agreement (CEPSA) with Powerex dated February 17, 2015, and accepted by Order E-10-15.

4.4 *FBC 2022/23 ANNUAL ELECTRIC CONTRACTING PLAN*

On May 2, 2022, FBC filed its 2022/23 Annual Electric Contracting Plan (AECP) with the BCUC. The purpose of the AECP is to outline FBC's plan to meet its peak demand requirements and

annual energy requirements for the operating year commencing October 1, 2022 and ending September 30, 2023, and to facilitate FBC's annual energy nomination under the PPA. FBC is required to take or pay for 75 percent of the PPA Nomination, regardless of whether it schedules the energy. The difference between the PPA Nomination and the 75 percent minimum take provides flexibility to manage annual loads that are below forecast or to displace PPA purchases with lower cost market purchases. Therefore, real-time opportunities to displace PPA purchases are restricted to a maximum of 25 percent of the PPA nominated energy, but could be more or less, depending on system conditions.[11] The AECP also outlines FBC's load and resource balance over the following four years, and FBC's plan for optimizing its portfolio over that period. FBC's forecasts of PPE for the remainder of 2022 and for 2023 are based on the plan detailed in the 2022/23 AECP, which was accepted by the BCUC on May 26, 2022, by Letter L-19-22.[12]

The AECP identified FBC's intention to make its annual energy nomination under the PPA for the 2022/23 contract year equal to 767 GWh, less any firm market contracts that FBC could enter into, as described in Section 5 of the 2022/23 AECP. Prior to the June 30, 2022 nomination deadline, FBC updated its forecast load and resource balance for the 2022/23 contract year and submitted a nomination of 774 GWh.

4.5 *2022 PROJECTED POWER PURCHASE EXPENSE*

As shown in Table 4-2 below, FBC's 2022 Projected gross load (after taking into account demand side management and other customer savings) is expected to be 195 GWh above the 2022 Approved value, and PPE is projected to be above the 2022 Approved value by $9.385 million. The increase in 2022 Projected PPE is primarily due to the increase in gross load above the 2022 Approved value. This increase in gross load drives increases in both the BC Hydro PPA and wholesale market expense to meet the additional load. In addition, increases in both the purchase price under the BC Hydro PPA and the average cost of purchases from the market further contributed to the increase in PPE.

[11] For example, if loads were 50 GWh lower in a year than forecast, that must be adjusted for as part of the 25 percent PPA flexibility such that the amount of PPA energy that can be displaced by market purchases is also reduced by 50 GWh.

[12] The AECP was filed confidentially. The non-confidential Executive Summary is attached to Letter L-19-22.

Table 4-2: 2022 Power Purchase Expense ($ millions)

Line No.	Description	Approved 2022	Projected 2022	Difference
1	Brilliant	$ 41.841	$ 42.367	$ 0.526
2	BC Hydro PPA	44.062	49.539	5.477
3	Waneta Expansion	42.701	41.434	(1.267)
4	Market and Contracted Purchases	15.102	21.672	6.570
5	Independent Power Producers	0.073	0.058	(0.015)
6	Self-Generators	-	-	-
7	CPA Balancing Pool	-	(1.252)	(1.252)
8	Transmission Service Loss Recoveries	-	-	-
9	Special and Accounting Adjustments	-	(0.654)	(0.654)
10	Total	$ 143.779	$ 153.164	$ 9.385
11				
12	Gross Load (GWh)	3,591	3,786	195

4.6 *2023 FORECAST POWER PURCHASE EXPENSE*

As shown in Table 4-3 below, the 2023 Forecast PPE is $10.412 million greater than the 2022 Projected. The forecast increase from $153.164 million in 2022 to $163.575 million in 2023 is mainly a result of a reduction in market and contracted purchases as they increase in price and correspondingly, a greater reliance on energy supplied by BC Hydro as it becomes more cost effective compared to market. Furthermore, as a result of load growth and uneconomic wholesale market prices, FBC expects to take Tranche 1 PPA energy over the nominated amount during 2023. Tranche 1 PPA energy taken over the nominated amount costs 150 percent of the Tranche 1 embedded cost rate,[13] and this exposure to more expensive PPA energy is also contributing to increased costs. Also contributing to the increase are escalations to the Waneta Expansion and Brilliant contract rates.

Table 4-3 below shows a comparison of the 2022 Projected and 2023 Forecast PPE. Reasons for significant variances from the 2022 Projected PPE are discussed below.

[13] $50.94 per MWh x 150 percent = $76.41 per MWh.

Table 4-3: 2023 Forecast Power Purchase Expense ($ millions)

Line No.	Description	Projected 2022	Forecast 2023	Difference
		-		
1	Brilliant	$ 42.367	$ 44.050	$ 1.683
2	BC Hydro PPA	49.539	71.302	21.763
3	Waneta Expansion	41.434	41.834	0.400
4	Market and Contracted Purchases	21.672	6.326	(15.346)
5	Independent Power Producers	0.058	0.062	0.004
6	Self-Generators	-	-	-
7	CPA Balancing Pool	(1.252)	-	1.252
8	Transmission Service Loss Recoveries	-	-	-
9	Special and Accounting Adjustments	(0.654)	-	0.654
10	Total	$ 153.164	$ 163.575	$ 10.412
11				
12	Gross Load (GWh)	3,786	3,775	(11)

4.6.1 Brilliant

Brilliant expense is forecast to increase in 2023 by $1.683 million compared to 2022 Projected due to increased rates, which are based on a forecast of the operating and maintenance cost of the plant, as well as a true-up to the prior year's actual costs compared to forecast.

4.6.2 BC Hydro PPA

BC Hydro PPA expense is forecast to increase in 2023 by $21.763 million compared to the 2022 Projected expense. The drivers of the increase are a higher purchased volume (371 GWh), which increases the expense by $21.775 million, and an increase in BC Hydro rates, which accounts for an increase of $3.987 million, for a total of $25.763 million. FBC has decreased its 2023 Forecast of PPA expense by $7.000 million in savings to account for potential real-time opportunities to displace PPA purchases with lower cost market purchases. The 2022 Projected BC Hydro expense was reduced by $3.000 million to account for potential real-time opportunities during the remainder of 2022. This results in a variance between 2022 Projected and 2023 Forecast of $21.763 million[14], as shown in Table 4-3. Actual market savings for the remainder of 2022 and 2023 may be higher or lower and will depend on system and market conditions at the time. Any variance, including these savings, is recorded in the Flow-through deferral account and returned to or recovered from customers in a subsequent year.

4.6.3 Waneta Expansion

The $0.400 million increase in Waneta Expansion expense is due to the 2.1 percent annual fixed escalation of WAX CAPA rates, offset by a $0.291 million increase in forecast surplus sales revenue under the RCA and CEPSA. Revenue under the CEPSA is linked to the amount of

[14] $21.763 million is calculated as follows: Total increase of $25.763 million less the $4.000 million variance between the 2022 Projected and 2023 Forecast real-time opportunities, or, $25.763 million – ($7.000 million - $3.000 million).

capacity FBC releases to Powerex and the day-ahead market prices at the Mid-Columbia River (Mid-C) trading hub. The Mid-C is the largest electricity trading hub in the Pacific Northwest and is located on the US portion of the Columbia River. FBC's forecast of Mid-C forward market prices is based on contracts that have been traded and/or bids and offers from forward contracts on the Intercontinental Exchange Inc. (ICE), which is a global exchange, clearing, financial data, and technology company. The method used to forecast market prices and surplus sales is the same as in the Annual Review for 2022 Rates. The forecast of surplus capacity sales revenue in 2023, which is included in line 3 of Table 4-3, is approximately $10.700 million.

4.6.4 Market and Contracted Purchases

The $15.346 million decrease in Market and Contracted Purchases forecast for 2023 is due to a lesser volume purchased at higher rates when compared to 2022 Projected. Market and Contracted Purchases for 2022 Projected include both fixed price contracted purchases and real-time market purchases made using the 25 percent flexibility of the PPA. All of the market purchases included in the 2023 Forecast are based on fixed price contracts executed by the Company, with the exception of forecast real-time market purchases for Rate Schedule 37[15] load. As discussed above in the BC Hydro PPA variance explanation, there may be opportunities for additional real-time market purchases using the flexibility of the PPA purchases.

4.6.5 CPA Balancing Pool

The CPA Balancing Pool represents timing differences in entitlement energy storage under the CPA and is used to manage fluctuations in load and resource availability, or to take advantage of market opportunities. In the 2022 Projected PPE, FBC has stored a net total of 25 GWh of entitlement energy, valued at $1.252 million. For the 2023 Forecast, and consistent with past practice, FBC does not forecast any net use or storage of entitlement energy.

4.7 *TRANSMISSION SERVICE LOSS RECOVERIES*

Transmission service customers taking service under FBC's Rate Schedules 100 and 101 currently physically deliver energy to FBC to compensate for the losses that are incurred on FBC's system as a result of wheeled energy. FBC includes transmission wheeling losses in its load forecast (included in Tables 4-2 and 4-3, line 8), and also includes loss recovery as a firm resource. Because the recoveries are delivered physically, there is no associated cost or revenue. Table 4-4 shows the 2022 and 2023 loss recoveries.

[15] RS 37 is large commercial stand-by service, which is on-demand back-up and maintenance service provided to self-generating customers. This service is provided to the customer at an hourly market-based rate, reflective of FBC's cost of supply. FBC procures this supply on a real-time basis because there is little certainty as to when customers will use this service. Forecast RS 37 load for 2023 is 15 GWh or 0.4 percent of total gross load.

Table 4-4: Transmission Service Loss Recoveries (GWh)

Line No.	Description	Approved 2022	Projected 2022	Forecast 2023
1	Loss Recoveries	12	12	12

4.8 WHEELING EXPENSE

Wheeling expense includes wheeling service provided by BC Hydro under the Amended and Restated Wheeling Agreement (ARWA) and Open Access Transmission Tariff (OATT) as needed to supply the Company's loads in the Okanagan, Creston and Princeton. Also included are charges paid to Teck Metals Ltd. (Teck) for the use of its 71 Line. Rates under the ARWA are specified in BC Hydro's RS 3817.

Wheeling expense is forecast using the same method as in the Annual Review for 2022 Rates. Table 4-5 below shows FBC's Wheeling Expense for 2022 and 2023.

Table 4-5: Wheeling Expense ($ millions)

Line No.	Description	Approved 2022	Projected 2022	Forecast 2023
1	Wheeling Nomination (MW Months)			
2	Okanagan Point of Interconnection	2,475	2,475	2,670
3	Creston	420	420	420
4				
5	Wheeling Expense			
6	Okanagan Point of Interconnection	$ 4.903	$ 4.976	$ 5.555
7	Creston	0.542	0.550	0.570
8	Other	0.648	0.804	0.863
9	Total Wheeling Expense	$ 6.093	$ 6.330	$ 6.987

Total 2022 Projected wheeling expense is $0.237 million greater than 2022 Approved. The 2022 Projected ARWA costs are $5.526 million (lines 6 and 7 in the table above), a $0.081 million increase when compared to 2022 Approved, which is a result of higher than expected BC-CPI and therefore ARWA rates. 2022 Projected Teck and OATT wheeling costs are $0.804 million (line 8 above), which is $0.156 greater than 2022 Approved. This is mainly due to increased use of OATT wheeling.

2023 Forecast wheeling expense is $0.657 million higher than 2022 Projected. This is a result of both increased use and rates. FBC increased the Okanagan wheeling nomination to 2,670 MW months in 2023 from 2,475 MW months in 2022. ARWA rates are forecast to increase on October 1 of both 2022 and 2023, based on forecast BC-CPI, as is the Teck wheeling rate as a result of a letter agreement made between Teck and FBC.

4.9 WATER FEES

Water fees are based on FBC's entitlement usage in the previous year and the rate increases are indexed to BC-CPI.

As shown in Table 4-6 below, the 2023 Forecast water fees are decreasing by $0.373 million from the 2022 Projected due to decreased entitlement use. 2023 water fees are forecast using the same method as in the Annual Review for 2022 Rates.

Table 4-6: Water Fees ($ millions)

Line No.	Description	Approved 2022	Projected 2022	Forecast 2023
1	Plant Entitlement in Previous Year (GWh)	1,679	1,663	1,571
2				
3	Water Fees	$ 11.958	$ 11.916	$ 11.543

4.10 SUMMARY

The primary objectives of FBC's power supply portfolio planning are to ensure that the Company has sufficient firm resources to meet expected load requirements, to ensure the availability of cost-effective reliable power for FBC's customers, to prudently manage exposure to the cost and availability of market power supplies, and to optimize the value of any surplus resources that are not needed to meet load requirements.

FBC's forecast of PPE is based on FBC's firm resources in place at the time of filing and is consistent with the 2022/23 AECP. Any variances in the power supply cost, including any decreases in PPE due to further portfolio optimization, are recorded in the Flow-through deferral account and returned to or recovered from customers in a subsequent year.

5. OTHER REVENUE

5.1 INTRODUCTION AND OVERVIEW

This section discusses FBC's forecasts of Other Revenue. In the MRP Decision (page 74), FBC was approved for variances between forecast and actual Other Revenue to be subject to earnings sharing.[16]

FBC is forecasting Other Revenue for 2023 to be $0.409 million higher than 2022 Approved, primarily due to higher Late Payment Charges and expected annual increases in rates for Apparatus and Facilities Rental, Contract Revenue and Transmission Access Revenue.

2022 Projected Other Revenue is $1.335 million higher than 2022 Approved. The main drivers of this increase are the sales of carbon credits related to Electric Vehicle (EV) Direct Current Fast Charging (DCFC) stations, as well as higher Contract Revenue and Late Payment Charges.

Table 5-1: Other Revenue ($ millions)

Line No.	Description	Approved 2022	Projected 2022	Forecast 2023
1	Apparatus and Facilities Rental	$ 6.018	$ 6.018	$ 6.108
2	Contract Revenue	2.277	2.750	2.367
3	Transmission Access Revenue	1.771	1.788	1.834
4	Interest Income	0.020	0.020	0.030
5	Late Payment Charges	0.875	1.095	0.994
6	Connection Charges	0.505	0.505	0.553
7	EV Stations Carbon Credits	-	0.625	-
8	Other Recoveries	0.366	0.366	0.355
9	Total Other Revenue	$ 11.832	$ 13.167	$ 12.241

In the following sections, FBC summarizes its projections and forecasts for each of the line items included in the table above.

5.2 APPARATUS AND FACILITIES RENTAL

Apparatus and Facilities Rental is comprised primarily of pole contact revenue from other utilities and businesses that attach their facilities to FBC infrastructure in order to deliver services to their customers, such as telephone and cable television providers. Rent is charged at a unit rate per pole contact multiplied by the number of poles that are contacted. There are no variances projected in 2022 compared to 2022 Approved, as final amounts have yet to be calculated since the majority of invoices are issued during the third quarter of the year. The 2023 Forecast is higher than 2022 Approved due to expected escalations in unit rental rates for continuing contracts.

[16] Variances in Other Revenue associated with Electric Vehicle (EV) stations carbon credits are treated as flow-through, as EV Direct Current Fast Charging (DCFC) stations are prescribed undertakings under section 5 of the GGRR and the cost of service associated with EV DCFC stations is subject to flow-through treatment.

5.3 CONTRACT REVENUE

FBC performs work under contract to third parties at the Waneta and Brilliant hydroelectric generating facilities. This third-party work, and the associated management fees earned, fluctuates from year to year based on customer requirements, which include routine and non-routine work planned at the start of the customer's fiscal year.

The Company also operates and maintains a number of other facilities for third-party entities through its non-regulated affiliate FortisBC Pacific Holdings Inc. (FPHI). Transactions between FBC and FPHI are conducted in accordance with FBC's Code of Conduct and Transfer Pricing Policy[17] and earn a transfer price profit revenue. Revenues may fluctuate from year to year depending on customer requirements.

The 2022 Projected revenue is higher than 2022 Approved due to an increase in costs related to the close-out of a multi-year asset refurbishment project for a third party that began in 2020, as well as certain costs that shifted from 2021 into 2022 for the same project. The 2023 Forecast is higher than 2022 Approved due to expected increases in the average cost of work and materials recovered from third-party customers.

5.4 TRANSMISSION ACCESS REVENUE

Transmission Access Revenue represents charges to customers for transmitting power over the FBC system. The 2022 Projected revenue is slightly higher than 2022 Approved due to a higher nomination than originally forecast for one customer. The 2023 Forecast is higher than 2022 Approved due to the phased increase in rates over three years beginning January 1, 2020, as approved by Order G-40-19.

5.5 INTEREST INCOME

Interest Income is primarily comprised of DSM loan interest income, as well as other banking interest income. The Company is not forecasting significant changes in the amount of DSM loans outstanding; as a result, no significant changes in interest income are expected in 2022 Projected or the 2023 Forecast.

5.6 LATE PAYMENT CHARGES

Late Payment Charges have historically been forecast based on the average of the most recent three years of actual Late Payment Charges earned. However, due to the impact of the COVID-19 pandemic and FBC's implementation of customer relief measures, which included the suspension of Late Payment Charges until March 2021, the actual amounts collected have fluctuated from year to year.

[17] As approved by Order G-5-10A.

FBC continues to see fluctuations in Late Payment Charges. The 2022 Projected Late Payment Charges are higher than 2022 Approved by $0.220 million based on amounts charged so far in 2022 as well as growth in customers since the 2017 to 2019 period used to develop the 2022 Approved.

In consideration of the continued fluctuations being experienced, the 2023 Forecast has been calculated based on the average of 2021 Actual and 2022 Projected Late Payment Charges of $0.892 million and $1.095 million, respectively. This results in an increase in Late Payment Charges of $0.119 million compared to 2022 Approved.

5.7 CONNECTION CHARGES

Connection Charges are calculated based on the fees specified in FBC's rate schedules applicable to new customer connections or current customer reconnections. The 2022 Projected is expected to be consistent with 2022 Approved based on amounts charged so far in 2022. The 2023 Forecast is expected to be higher than 2022 Approved based on customer growth and forecast customer reconnections.

5.8 CLEAN GROWTH INITIATIVE – EV DCFC STATIONS CARBON CREDITS

FBC's EV DCFC stations are prescribed undertakings under section 5 of the GGRR[18] and the cost of service associated with EV DCFC stations is subject to flow-through treatment. The EV charging rates, the depreciation rate for EV charging stations, and the inclusion of related revenues and expenses associated with FBC's EV DCFC stations in FBC's regulated accounts were approved by the BCUC on November 24, 2021[19]. The revenues to be included in FBC's regulated accounts include the Other Revenue from the sale of carbon credits related to EV stations[20] earned under the Renewable Low Carbon Fuel Requirements Regulation (RLCFRR), which is embedded in the rate design of the EV DCFC stations.

At the time of the 2022 Annual Review, FBC did not have any carbon credits validated by the British Columbia Low Carbon Fuel Standard (BC-LCFS); as such, and as reflected in Table 5-1 above, FBC did not forecast any revenue from the sales of the credits for 2022 Approved. However, as of the end of the first quarter of 2022, the BC-LCFS has validated approximately 1,337 carbon credits for FBC that have accumulated since 2019, with an approximate market value of $0.625 million[21]. FBC anticipates monetizing these credits prior to the end of 2022 and has therefore reflected them in the 2022 Projected column in Table 5-1 above, and also included the $0.625 million credit in the Flow-through deferral account, to be returned to customers in 2023.

[18] Order G-215-21 dated July 14, 2021.
[19] FBC EV DCFC Service Application Decision and Order G-341-21.
[20] Includes both public charging stations owned by FBC as well as public stations owned by other entities (metered commercial accounts) as discussed in Exhibit B-6 of FBC's 2022 Annual Review, BCSEA IR1 4.3. Beginning in 2022, FBC will only be permitted to claim credits for charging stations owned by FBC. FBC does not currently claim credits for non-public EV charging services for either commercial or residential customers.
[21] 1,337 credits x $467.32 average Q1-2022 sales price (source: https://www2.gov.bc.ca/assets/gov/farming-natural-resources-and-industry/electricity-alternative-energy/transportation/renewable-low-carbon-fuels/rlcf-017.pdf).

Consistent with the practice from the 2022 Annual Review, FBC does not forecast revenue from the sale of credits that are pending validation; FBC is therefore not forecasting any of these revenues in 2023.

As part of the 2022 Annual Review Decision, FBC was directed to include the following in future Annual Review filings:[22]

> …an update on its EV DCFC charging stations' costs and revenues for the previous fiscal year along with a forecast of costs and revenues for the test period.

FBC currently has a total of 40 EV DCFC stations in service across 23 sites and is planning to install two additional DCFC stations at two of the existing sites in 2022, resulting in a total of 42 EV DCFC stations across 23 sites. Consistent with the format of the information provided during the 2022 Annual Review[23], Table 5-2 below provides the costs and revenues for 2021 Actual (previous fiscal year), 2022 Projected, and 2023 Forecast. As highlighted in Table 3-4 of Section 3.6, the RS 96 EV DCFC revenue (i.e., Line 10 of Table 5-2 below) is included as part of the Commercial Sales Revenue. Please also refer to Section 6.3.4 for a discussion of the forecast O&M expenses for the EV DCFC stations and Section 7.2.2 for a discussion of the forecast capital expenditures for the EV DCFC stations, as well as information on how the two new stations are prescribed undertakings. Once the capital expenditures are included in rate base, they impact the depreciation, amortization of CIAC, income tax and earned return related to the EV DCFC stations that are shown in Table 5-2 below.

Table 5-2: EV DCFC Stations Costs and Revenues for 2021 Actual, 2022 Projected, and 2023 Forecast ($ millions)[24]

Line	Particulars	2021 Actual	2022 Projected	2023 Forecast	Cumulative
1	Cost of Energy	0.013	0.282	0.300	
2	Less: Power Purchase Expense	(0.013)	-	-	
3	O&M	0.101	0.187	0.193	
4	Depreciation	0.307	0.456	0.612	
5	Amortization of CIAC	(0.150)	(0.191)	(0.249)	
6	Other Revenue - Carbon Credits	-	(0.625)	-	
7	Income Tax	(0.299)	(0.199)	0.158	
8	Earned Return	0.124	0.172	0.183	
9	Total Cost of Service	0.083	0.082	1.196	
10	RS 96 Revenue	(0.058)	(0.155)	(0.178)	
11	(Surplus) / Deficiency	0.025	(0.072)	1.018	0.971
12	Prior Year 2018-2020 (Surplus)/Deficiency				(0.142)
13	Cumulative (Surplus) / Deficiency				0.828

[22] FBC 2022 Annual Review Decision and Order G-374-21, p. 32.
[23] Exhibit B-3, BCUC IR1 16.1.
[24] As explained in Exhibit B-3, BCUC IR1 16.1 of the FBC 2022 Annual Review, RS 96 was approved on an interim basis in 2021 by Order G-9-18 in which the cost of energy embedded was based on BC Hydro's RS 3808; therefore,

As directed by Order G-341-21, FBC is to file a detailed assessment of the EV DCFC service by no later than December 31, 2022 or within six months of Measurement Canada's approval of DCFC energy-based metering for FBC, whichever is earlier. FBC is not expecting to receive approval from Measurement Canada prior to December 31, 2022; thus, FBC will file the detailed assessment report by December 31, 2022. As directed by the BCUC, the detailed assessment will include:

- An update of the financial models with actual and forecast information and updated assumptions;
- A detailed assessment of RS 96 and alternative rate design options;
- An overview of the current EV fast charging service market and rates across Canada and the United States;
- A proposal for a depreciation rate for its EV DCFC stations and information to support its proposal; and
- An assessment as to whether idling fees are warranted.

5.9 *OTHER RECOVERIES*

Other Recoveries are primarily comprised of fees earned on the recovery of costs for miscellaneous services, such as street light maintenance charged to municipalities and AMI radio-off meter read fees. There are no variances expected in 2022 Projected compared to 2022 Approved based on amounts recognized to date. The 2023 Forecast is expected to be slightly lower than 2022 Approved due to an expected reduction in AMI radio-off meter read fees resulting from a lower volume of customers choosing the radio-off option.

5.10 *SUMMARY*

FBC has forecast the Other Revenue components for 2023 reflecting all applicable contracts and fixed revenues, and based on the Company's best knowledge of the factors that drive the variable components. Variances in Other Revenue, with the exception of EV DCFC stations carbon credits, are shared with customers through the earnings sharing mechanism.

the cost of energy for 2021 Actual shown in Table 5-2 is equal to the power purchase expense. As approved in Order G-341-21, the permanent rate for RS 96 is based on FBC's commercial service RS 21. As such, starting in 2022, the cost of energy shown in Table 5-2 above is based on FBC's commercial service RS 21.

6. O&M EXPENSE

6.1 INTRODUCTION AND OVERVIEW

Under the MRP, FBC's O&M expense is primarily determined by formula, with the addition of a number of items that are forecast outside the formula on an annual basis.

In 2023, the formula O&M is $69.957 million, representing a 5.8 percent increase from the 2022 formula O&M, primarily due to the formula drivers. O&M expenses forecast outside the formula for 2023 are $2.323 million, representing a 26.8 percent increase from the amount approved for 2022. Overall, the 2023 Forecast gross O&M expense is $72.789 million, which is an increase of approximately 7.0 percent from the 2022 Approved level.

The components of 2023 O&M expense are shown in Table 6-1 below.

Table 6-1: 2023 O&M Expense ($ millions)

Line No.	Description	Approved 2022	Projected 2022	Forecast 2023	Reference
1	Formula O&M	$ 66.147	$ 66.147	$ 69.957	Section 11, Schedule 20, Line 8
2	Forecast O&M	1.832	1.635	2.323	Section 11, Schedule 20, Line 20
3	Prior year O&M True-up	0.053	0.053	0.509	Table 6-2, line 16
4	Total Gross O&M	68.032	67.835	72.789	Line 1 through 3
5	Capitalized Overhead	(10.177)	(10.177)	(10.918)	Section 11, Schedule 20, Line 23
6	Net O&M	$ 57.855	$ 57.658	$ 61.871	Line 4 + Line 5

In the sections below, FBC provides further details on its formula and forecast O&M expenses for 2023. Additionally, in compliance with the BCUC's directive in the MRP Decision,[25] FBC provides information related to its System Operations, Integrity and Security expenditures in Subsection 6.2.1.

6.2 FORMULA O&M EXPENSE

The formula-driven portion of O&M starts from the prior year's Approved Base O&M per Customer (UCOM), escalated by the prior year's inflation less a productivity improvement factor of 0.5 percent, and then multiplied by 75 percent of the forecast growth in average customers, resulting in the current year inflation-indexed O&M before true-up. A true-up of formula O&M based on actual average customers from two years prior is then added to the current year inflation-indexed O&M.

As calculated in Section 2, the 2023 inflation based on prior year's BC-CPI and BC-AWE, less the productivity improvement factor, is 4.017 percent.

For 2023, the annual operating and maintenance expense under the formula is calculated as:

[25] MRP Decision, p. 118.

2022 Approved formula UCOM x [1 + (I Factor – X Factor)] x [Prior Year Average Customers + (0.75 x growth in average customers)] + 2021 Formula O&M True-up

Table 6-2 below shows the calculation of the 2023 Formula O&M, including the calculation of the 2021 Formula O&M true-up. FBC notes the true-up of formula O&M is a two-year lag based on actual average customer counts from 2021.

Table 6-2: Calculation of 2023 Formula O&M ($ millions)

Line No.	Description		Forecast 2023	Reference
1	Prior Year Base Unit Cost O&M ($/ customer)	$	455	G-374-21 FBC 2022 Annual Review
2	I-Factor		4.017%	Section 2, Table 2-3, Line 11
3	Current Year Unit Cost O&M ($/customer)	$	473	
4	Average Customer Forecast		147,901	Section 2, Table 2-3, Line 13
5	2023 Inflation-Indexed O&M before 2020 True-up	$	69.957	Line 3 x Line 4 / 1,000,000
6	2021 True-up O&M		0.509	Line 16
7	Inflation-Indexed O&M	$	70.466	Line 5 + Line 6
8				
9	2021 O&M True-up			
10	2021 Actual 12 month Average Customers		144,877	FBC 2021 Annual Report
11	2021 Forecast 12 month Average Customers		143,325	G-42-21 FBC 2020-2021 Annual Review
12	Difference		1,552	Line 10 + Line 11
13	Growth Factor		75%	G-166-20 FBC MRP Decision
14	Change in Customers - True-up		1,164	Line 12 x Line 13
15	2021 Unit Costs	$	437	G-42-21 FBC 2020-2021 Annual Review
16	O&M True-up for 2023	$	0.509	Line 14 x Line 15 / 1,000,000

6.2.1 New/Incremental System Operations, Integrity and Security Funding

In the MRP Decision (page 118), the BCUC directed FBC to provide in each Annual Review a breakdown and explanation of both annual and cumulative variances between forecast/actual and formula O&M related to the approved new/incremental System Operations, Integrity and Security funding, and quantify the variances attributable to the following areas: tree management; generation dam safety; network operations apprentice program; cyber security; data analytics; and any other significant factors or miscellaneous items.

The table below shows the requested information, including the new/incremental funding in each category for 2021 Formula O&M, 2021 Actual O&M, and the resulting variances, as well as the Cumulative Forecast/Actual variance for the first two years of the MRP.

Table 6-3: System Operations, Integrity and Security New/Incremental Spending ($ millions)

Line No.	Description	2021 Formula O&M[1]	Actual 2021 O&M	2021 Forecast/Actual Variance	Cumulative Forecast/Actual Variance[2]
1	Tree Management	$ 0.080	$ 0.278	$ 0.199	$ 0.436
2	Generation Dam Safety	$ 0.246	$ 0.415	$ 0.169	$ 0.137
3	Network Operations Apprentice Program	$ 0.209	$ 0.243	$ 0.034	$ (0.167)
4	Cyber Security	$ 0.085	$ 0.085	$ -	$ 0.250
5	Data Analytics	$ 0.105	$ -	$ (0.105)	$ (0.206)
6	Other	$ -	$ -	$ -	$ -
7	Total	$ 0.724	$ 1.021	$ 0.297	$ 0.449

Notes to Table:

[1] 2021 Formula O&M is the approved 2020 formula for incremental funding with Net Inflation factor applied (3.668%).
[2] Cumulative Forecast/Actual variance is the 2020 Actual variance plus the 2021 Actual variance.

Overall, total actual spending in 2021 was $1.021 million, which is $0.297 million higher than the 2021 Formula O&M amount. Areas with notable variances include tree management, generation dam safety and data analytics.

For tree management, FBC spent $0.199 million more than the formula amount to address an increased number of unhealthy trees as part of FBC's right-of-way management program.

For generation dam safety, FBC spent $0.169 million more than the formula amount due to the continuation of dam safety review activities from 2020, as FBC required more time to complete the analysis for the determination of the dam classifications for the Upper Bonnington, Lower Bonnington and South Slocan plants.

Offsetting the higher costs in these two categories was lower spending in data analytics. FBC spent $0.105 million less than the formula amount in 2021 primarily due to labour savings from a delay in hiring. In 2021, FBC focused on finalizing the requirements for the necessary information infrastructure, with the implementation of the systems that will allow centralized data access occurring in 2022 and the addition of new data sources in priority sequence over the remaining term of the MRP.

For the first two years of the MRP, FBC spent $0.449 million more than the formula amount. Over the term of the MRP, FBC anticipates the total new/incremental spending required in the combined categories of System Operations, Integrity and Security will continue to be higher than the amount embedded in the formula. FBC will continue to manage this spending within its overall O&M spending envelope.

6.3 *O&M EXPENSE FORECAST OUTSIDE THE FORMULA*

In addition to FBC's formula O&M, FBC forecasts a number of O&M items outside of the formula annually, including pension and OPEB expense, insurance premiums, BCUC levies, and the cost

of service associated with Clean Growth initiatives, such as Electric Vehicle (EV) charging stations, as well as the O&M impacts of any exogenous factor items. For 2023, FBC has included incremental O&M for the Mandatory Reliability Standards (MRS) Assessment Report No. 13 (AR13), which was approved for exogenous treatment in the 2022 Annual Review.

The 2023 amounts are shown in Table 6-4 below along with a comparison to 2022.

Table 6-4: 2023 Forecast O&M ($ millions)

Line No.	Description	Approved 2022	Projected 2022	Forecast 2023
1	Pension/OPEB (O&M Portion)	$ (1.716)	$ (1.716)	$ (1.297)
2	Insurance Premiums	2.223	2.291	2.457
3	BCUC Levies	0.373	0.373	0.385
4	Clean Growth Initiative - EV DCFC Stations	0.187	0.187	0.193
5	Exogenous Factor - MRS	0.765	0.500	0.585
6	Total Forecast O&M	$ 1.832	$ 1.635	$ 2.323

Each of the items that is forecast outside of the formula is discussed below. Variances in pension and OPEB expense are captured in the Pension and OPEB Variance deferral account and variances in BCUC levies are captured in the BCUC Levies Variance deferral account. Variances in insurance premiums, the cost of service associated with EV charging stations, and exogenous factors are captured in the Flow-through deferral account.

6.3.1 Pension and OPEB Expense

Pension and OPEB expense for 2023 is based upon actuarial estimates using a range of assumptions as of December 31, 2021 with an update of discount rate estimates as of April 30, 2022 provided by the Company's external third party actuary, Willis Towers Watson. The discount rate determined reflects the market yields of high quality Canadian corporate bonds which have increased since 2021. In addition to O&M, pension and OPEB expense is embedded in Capital Expenditures, as shown in Table 6-5.

Table 6-5: Pension and OPEB Expense ($ millions)

Line No.	Description	Approved 2022	Projected 2022	Forecast 2023
1	O&M	$ (1.716)	$ (1.716)	$ (1.297)
2	Capital (Approved)	3.807	3.807	1.888
3	Capital (to Pension & OPEB Variance Deferral)[1]	(0.400)	(0.400)	-
4	Total	$ 1.691	$ 1.691	$ 0.591

Notes to Table:

[1] This line item represents the pension and OPEB expense difference between the estimates embedded in the Regular Capital Expenditure forecasts on Line 2 in this table, which were based on the pension and OPEB actuarial estimates provided in 2019 as part of the 2020 to 2024 MRP Application, and the actuarial estimates

updated for 2023 rate-setting purposes. There is no difference for 2023 since FBC was directed to file an updated forecast of the 2023 and 2024 Regular Capital Expenditures in the 2023 Annual Review, as directed in the MRP Decision and Order G-166-20.

The variance between the 2022 Approved and actual pension and OPEB expense, including the known capital variance on Line 3 of Table 6-5 above, and any variance between the 2023 Forecast and actual amounts, is flowed through to the Pension and OPEB Variance deferral account and amortized into rates over a three-year period, as approved by Order G-139-14.

The 2023 Forecast pension and OPEB expense has decreased by $1.100 million compared to the 2022 Approved expense primarily due to the following factors, which are all components of pension and OPEB expense:

- An approximate $3 million decrease in current service costs due to an increase in the discount rate. The discount rate, which is determined with reference to the market rate of interest on high quality debt instruments at a point in time, increased from 3.5 percent, which was used to determine the 2022 Approved expense, to 4.5 percent, which is used to determine the 2023 Forecast expense;

offset in part by:

- An approximate $2 million increase in interest costs due to an increase in the discount rate.

6.3.2 Insurance Premiums

The component of insurance expense tracked outside of formula O&M relates to the insurance premium expense allocated to FBC by Fortis Inc. as set out in Table 6-6 below.

Table 6-6: Insurance Premiums ($ millions)

Line No.	Description	Approved 2022	Projected 2022	Forecast 2023	Reference
1	Insurance Premiums	$ 2.223	$ 2.291	$ 2.457	Section 11, Schedule 20, Line 16
2	Total	$ 2.223	$ 2.291	$ 2.457	

The 2022 Projected insurance premium expense of $2.291 million is $0.068 million higher than 2022 Approved, as it incorporates FBC's actual July 2022 to June 2023 insurance renewals of $2.253 million. The higher premiums experienced in 2022 are expected to continue into 2023, though at a lower rate of increase. The 2023 Forecast is $2.457 million, which is an increase of $0.166 million from 2022 Projected. The 2023 Forecast is calculated as the amount of the first six months of actual annual insurance premiums for January to June 2023 of $1.126 million and

applying a 5 percent increase for the remaining six months, plus the cost of fire fighting services FBC pays to the Province of $0.148 million.[26]

6.3.3 BCUC Levies

FBC's 2023 Forecast for BCUC levies is $0.385 million. The 2023 Forecast is based on Order G-188-22 for the BCUC's Fiscal 2022/23 year, which represents the best information available at this time, as the BCUC levy calculation for Fiscal 2023/24 will not be available until early or mid 2023.

BCUC levies receive flow-through treatment, with annual variances between actual and forecast amounts in O&M expense being recorded in the BCUC Levies Forecast Variance deferral account and amortized over one year.

6.3.4 Clean Growth Initiative – Electric Vehicle (EV) DCFC Stations

As discussed in Section 5.8, FBC's EV DCFC stations are prescribed undertakings under section 5 of the GGRR[27] and the cost of service associated with EV DCFC stations is subject to flow-through treatment. Please refer to Table 5-2 in Section 5.8 which provides a summary of the EV DCFC stations' costs and revenues from 2021 Actual to 2023 Forecast.

As shown in Table 6-7 below, the 2022 Projected EV DCFC station O&M expense is expected to be consistent with 2022 Approved[28], and consists of network management, repairs and maintenance, inspection fees and FBC labour costs. The 2023 Forecast EV DCFC station O&M expense is anticipated to be similar to the 2022 Projected level, with an approximate increase of $6 thousand primarily due to inflation.

Table 6-7: Clean Growth Initiative – EV DCFC Stations ($ millions)

Line No.	Description	Approved 2022	Projected 2022	Forecast 2023	Reference
1	Clean Growth Initiative - EV DCFC	$ 0.187	$ 0.187	$ 0.193	Section 11, Schedule 20, Line 19
2	Total	$ 0.187	$ 0.187	$ 0.193	

6.3.5 MRS Incremental Operating Expenses

In the 2022 Annual Review Decision,[29] FBC received approval of exogenous factor treatment for the incremental O&M and capital costs associated with MRS AR13. As explained in the 2022

[26] $2.253 million/2 = $1.126 million. $1.126 million x 1.05 = $1.183 million. $1.126 million + $1.183 million + $0.148 million annual firefighting service fee = $2.457 million.
[27] Order G-215-21 dated July 14, 2021.
[28] Consistent with the 2022 Annual Review Decision, FBC included the 2022 forecast revenues and expenses associated with the EV DCFC stations in the Compliance Filing to the Annual Review Decision and Order G-374-21 because approval of the EV DCFC Service Application was not received until November 24, 2021. Accordingly, the 2022 Approved amount reflected in Table 6-7 is the amount included in the Compliance Filing.
[29] Decision and Order G-374-21, p. 21.

Annual Review, FBC expected to incur one-time costs in 2021 and 2022 related to the adoption of the standards in AR13 as well as ongoing incremental O&M expenses commencing in 2023[30].

BC Hydro issued AR13 on May 1, 2020 recommending adoption of seven standards, retirement of one standard, and holding one standard in abeyance pending resolution of the Planning Coordinator (PC) function along with the NERC Glossary dated August 12, 2019. The BCUC issued Order R-19-20 on September 8, 2020 accepting BC Hydro's recommendation and determined the effective dates of those standards. Of the standards and respective NERC Glossary terms assessed by FBC, five standards have associated costs, of which one was held in abeyance. The effective date for the four adopted standards is April 1, 2023, including the existing CIP-005-6 (Electronic Security Perimeter(s)), CIP-008-6 (Incident Reporting and Response Planning) and CIP-010-3 (Configuration Change Management and Vulnerability Assessments) standards and the new CIP-013-1 (Supply Chain Risk Management) standard. In order to address these changes, FBC is required to monitor and disconnect vendor remote access, evaluate and report attempts to compromise, ensure software downloads and installations are unaltered and secure, and assess risk for any product or service procured for Bulk Electrical System assets under the Critical Infrastructure and Protection (CIP) standards. These requirements are reflected in the 2022 Approved, 2022 Projected, and 2023 Forecast expenses in Table 6-8 below.

The following table provides the 2022 Approved and Projected and the 2023 Forecast of incremental O&M related to MRS AR13.

Table 6-8: Incremental O&M for MRS AR13 ($ millions)

Line No.	Description	Approved 2022	Projected 2022	Forecast 2023	Reference
1	Labour	$ 0.335	$ 0.200	$ 0.490	
2	Non-Labour	0.280	0.250	0.095	
3	Contingency	0.150	0.050	-	
4	Total	$ 0.765	$ 0.500	$ 0.585	Section 11, Schedule 20, Line 18

The 2022 Projected O&M expense is lower than 2022 Approved by $0.265 million. The reduction of $0.265 million is a result of less overall effort required to modify existing programs and processes as mentioned above than originally expected.

The 2023 Forecast O&M expense of $0.585 million is related to the expected ongoing efforts to maintain procedures and processes, hardware and software that address supply chain risk assessments, ongoing licensing and maintenance of the hardware and software, and the documentation to maintain compliance of AR13. The 2023 Forecast is based on the expected costs in 2022 Projected and is therefore less than the 2022 Approved level. These costs are annual and will continue in future years.

[30] Exhibit B-2, Annual Review for 2022 Rates Application, Section 12.2.1, pp. 103-104; Exhibit B-3, BCUC IR1 24.2.

6.4 NET O&M EXPENSE

Net O&M expense is gross O&M less capitalized overhead. As approved by the BCUC in Order G-166-20, the capitalized overhead rate is set at 15 percent for FBC, unchanged from 2022. After capitalized overhead, the net O&M expense is $61.871 million in 2023.

6.5 SUMMARY

Overall, the increase in gross O&M expense from 2022 Approved to 2023 Forecast is 7.0 percent. Formula-driven O&M is increasing at a rate of 5.8 percent, and O&M forecast outside the formula is 26.8 percent higher than 2022 Approved.

The capitalized overhead rate for 2023 remains unchanged from 2022.

7. RATE BASE

7.1 INTRODUCTION AND OVERVIEW

FBC forecasts its Rate Base to be $1.675 billion for 2023. Rate Base is comprised of mid-year net plant in service, work in progress not attracting AFUDC, unamortized deferred charges, working capital, and the utility plant acquisition adjustment.[31]

FBC's 2023 Rate Base includes the full-year impacts of the 2022 closing projected plant balances as well as the impact of the following amounts:

- Mid-year impact of regular capital additions, net of CIAC additions, of $94.209 million;
- Mid-year impact of plant depreciation, net of CIAC amortization, of $64.407 million; and
- Capital additions of CPCNs and other Major Projects totalling $45.439 million[32], as discussed in Section 7.3 below, which include:
    - Full-year impact of $21.250 million for the capital expenditures and related AFUDC for the Kelowna Bulk Transformer Additions (KBTA) Project, which is expected to complete in late 2022 or early 2023;
    - Full-year impact of $16.151 million for the final capital expenditures and related AFUDC for the Corra Linn Dam Spillway Gates Replacement Project, which is expected to complete in 2022; and
    - Full-year impact of $8.036 million for the final capital expenditures and related AFUDC for the Playmor Substation Upgrade Project, which is expected to complete in 2022.

In addition, various changes in deferred charges, working capital and other items increase rate base by a net amount of $24.303 million in 2023.

Details of the 2023 Forecast plant balances can be found in Section 11, Schedules 5 through 9.

7.2 REGULAR CAPITAL EXPENDITURES

As part of the MRP Decision and Order G-166-20, FBC received the following approvals for capital expenditures:

- Approval of FBC's forecasts submitted for regular capital expenditures for the years 2020 through 2022; and

[31] The utility plant acquisition adjustment relates to the 1982 purchase of Plants 2, 3, and 4 and is being amortized over a period of 64 years.

[32] The 2023 capital additions of $45.439 million also include $0.002 million for the close out costs and related AFUDC in 2022 for the UBO Old Units Refurbishment Project.

- Approval of a number of items to be forecast on an annual basis.

Further, in the MRP Decision the BCUC directed FBC to file an updated forecast of the 2023 and 2024 regular capital expenditures in the 2023 Annual Review.[33]

The components of FBC's 2023 regular capital expenditures are shown in Table 7-1 below.

Table 7-1: Regular Capital Expenditures ($ millions)

Line No.	Description	Approved 2022	Projected 2022	Forecast 2023	Reference
1	Forecast Capital	$ 81.925	$ 87.735	$ 94.428	Table 7-2 and Table 7-3, Line 4
2	Flow-Through Capital	0.935	2.430	0.248	Table 7-11, Line 3
3	Total Gross Regular Capital	$ 82.860	$ 90.165	$ 94.676	Sum of Lines 1 & 2
4	Less CIAC	(11.712)	(8.287)	(11.628)	Section 11, Schedule 9, Line 2
5	Net Regular Capital	$ 71.148	$ 81.878	$ 83.048	Sum of Lines 3 & 4

In Section 7.2.1, FBC provides its updated 2023 and 2024 regular capital forecasts. In Section 7.2.2, FBC provides details on its forecast flow-through expenditures for 2023, consistent with the format provided in previous annual reviews during this MRP term.

7.2.1 Updated 2023 and 2024 Forecast Regular Capital Expenditures

As stated above, in the MRP Decision and Order G-166-20[34], the BCUC directed FBC to file updated 2023 and 2024 regular capital forecasts as part of the 2023 Annual Review. The BCUC in its decision highlighted FBC's evolving operating environment and inherent uncertainties in the capital forecasts, and thus considered it appropriate for FBC to have the opportunity to true-up its capital spending and re-forecast its capital for the final two years of the MRP term. Specifically, the BCUC stated the following:

> …FEI and FBC face evolving operating environments and there are inherent uncertainties in the five-year forecast. Reviewing the capital forecast in 2022 allows for a review of any significant variances between forecast and actual to date and provides an opportunity to true-up the rate-base for actual spending and to re-forecast the remaining years in the MRP term.[35]

As further explained below, FBC has begun to experience pressures due to a variety of factors which are outside of the Company's control and could not have been anticipated at the time of the MRP proceeding, including supply chain issues and rising commodity prices and other inflationary pressures brought on by the COVID-19 pandemic and the war in Ukraine. These factors, as well as the increased cost and complexity in permitting and land acquisition as well as increased growth, are impacting FBC's ability to execute on all of its planned capital projects and programs. While FBC has pursued various mitigation measures to manage through the spending

[33] MRP Decision and Order G-166-20, p. 131.
[34] Directive 1.c. of Order G-166-20.
[35] MRP Decision and Order G-165-20, p. 131.

pressures, FBC requires an increase in its capital spending for 2023 and 2024 compared to its original forecasts to execute on its planned activities.

The following tables summarize the growth, sustainment and other capital expenditures[36]. The first table presents the 2020 through 2022 Approved forecasts (i.e., the forecasts approved in the MRP Decision) and the 2023 and 2024 forecasts which were reviewed during the MRP proceeding (Original Forecasts). The second table provides the Actual/Projected results for 2020 through 2022 and FBC's updated forecasts for 2023 and 2024 (Updated Forecasts).

Table 7-2: Regular Capital Expenditures, 2020-2022 Approved and 2023-2024 Original Forecasts ($ millions)

Line No.	Description	Approved 2020	Approved 2021	Approved 2022	Original Forecast 2023	Original Forecast 2024
1	Growth Capital	27.029	23.042	24.339	26.283	23.170
2	Sustainment Capital	50.463	49.818	42.830	44.377	53.470
3	Other Capital	15.752	14.712	14.756	15.281	15.134
4	Total	93.244	87.573	81.925	85.941	91.774

Table 7-3: Regular Capital Expenditures, 2020-2021 Actual, 2022 Projected and 2023-2024 Updated Forecasts ($ millions)

Line No.	Description	Actual 2020	Actual 2021	Projected 2022	Updated Forecast 2023	Updated Forecast 2024
1	Growth Capital	28.799	21.865	29.868	30.973	24.568
2	Sustainment Capital	47.325	49.601	41.486	45.797	58.673
3	Other Capital	16.036	15.349	16.381	17.658	17.213
4	Total	92.160	86.815	87.735	94.428	100.454

In Section 7.2.1.1, FBC describes its updated forecasts for growth and sustainment capital. In Section 7.2.1.2, FBC describes its updated forecasts for other capital.

7.2.1.1 Growth and Sustainment Capital

7.2.1.1.1 GROWTH CAPITAL

Growth capital expenditures involve transmission and distribution system improvements required to meet incremental customer and load growth, in addition to the cost of connecting new customers to the system.

The three main growth capital portfolios are: (i) Transmission Growth; (ii) Distribution Growth; and (iii) New Connects. In the MRP Application, FBC provided forecasts of these three categories of

[36] Excluding sustainment CIAC.

growth capital expenditures based on a bottom-up approach which included a two percent inflationary increase per year.

The following tables provide the 2020 to 2022 Approved vs Actual/Projected expenditures and the Original and Updated 2023 and 2024 Forecasts.

Table 7-4: Growth Capital Expenditures 2020-2022 ($ millions)

Line No.	Description	2020 Approved	2020 Actual	2021 Approved	2021 Actual	2022 Approved	2022 Projected
1	Transmission Growth	5.172	7.109	2.063	0.744	2.740	5.524
2	Distribution Growth	3.716	1.926	1.876	1.965	1.807	3.450
3	New Connects	18.141	19.764	19.104	19.156	19.792	20.894
4	Total Growth Capital	27.029	28.799	23.042	21.865	24.339	29.868

Table 7-5: Growth Capital Expenditures 2023 and 2024 ($ millions)

Line No.	Description	2023 Original Forecast	2023 Updated Forecast	2024 Original Forecast	2024 Updated Forecast
1	Transmission Growth	5.195	6.223	1.086	1.088
2	Distribution Growth	1.899	2.800	1.921	1.716
3	New Connects	19.188	21.951	20.163	21.764
4	Total Growth Capital	26.283	30.973	23.170	24.568

As shown in Table 7-5 above, FBC's Updated Forecasts for growth capital have increased by $4.690 million in 2023 and $1.398 million in 2024 compared to the Original Forecasts. FBC is forecasting increases in all three growth capital portfolios in 2023. For 2024, the increase is primarily in the New Connects portfolio, with FBC reducing the expenditures for the Distribution Growth portfolio to offset some of the required increases. These increases are described in Section 7.2.1.1.3 below.

7.2.1.1.2 SUSTAINMENT CAPITAL

The expenditures within sustainment capital include system improvements to the transmission and distribution system in order to maintain existing equipment to meet forecast load and for the safety, reliability and quality of the system. FBC operates and maintains four generating facilities with a total of 15 units. FBC regularly monitors its infrastructure to ensure it meets industry standards and guidelines, complies with regulations, and operates safely to minimize risk to the public and employees. FBC also identifies and addresses hazards and risks that require immediate attention through specific projects. FBC's telecommunications system is an integral component in the protection relaying system, remedial action schemes, substation operations and control, and generation dispatch systems. The system requires ongoing investment to replace aging or failed systems for safe and reliable operation of the system and to ensure business needs continue to be met.

The five main sustainment capital portfolios are: (i) Generation; (ii) Transmission Sustainment; (iii) Stations Sustainment; (iv) Distribution Sustainment; and (v) Telecommunications. In the MRP

Application, FBC provided forecasts of these five categories of sustainment capital expenditures based on a bottom-up approach which included a two percent inflationary increase per year.

The following tables provide the 2020 to 2022 Approved vs Actual/Projected expenditures and the Original and Updated 2023 and 2024 Forecasts.

Table 7-6: Sustainment Capital Expenditures 2020-2022 ($ millions)

Line No.	Description	2020 Approved	2020 Actual	2021 Approved	2021 Actual	2022 Approved	2022 Projected
1	Generation	6.697	5.884	6.766	6.949	6.309	6.731
2	Transmission Sustainment	8.353	12.506	6.387	10.667	5.698	7.841
3	Stations Sustainment	13.538	4.821	13.624	12.083	5.279	6.889
4	Distribution Sustainment	20.057	21.530	20.058	17.479	19.262	17.439
5	Telecommunications	1.818	2.584	2.983	2.423	6.280	2.587
6	Total Sustainment Capital	50.463	47.325	49.818	49.601	42.830	41.486

Table 7-7: Sustainment Capital Expenditures 2023 and 2024 ($ millions)

Line No.	Description	2023 Original Forecast	2023 Updated Forecast	2024 Original Forecast	2024 Updated Forecast
1	Generation	7.008	7.623	6.514	7.225
2	Transmission Sustainment	7.951	9.159	7.591	12.800
3	Stations Sustainment	3.793	7.928	15.971	15.229
4	Distribution Sustainment	19.710	17.480	19.922	18.219
5	Telecommunications	5.915	3.606	3.472	5.199
6	Total Sustainment Capital	44.377	45.797	53.470	58.673

As shown in Table 7-7 above, FBC's Updated Forecasts for sustainment capital have increased by $1.420 million in 2023 and $5.203 million in 2024 compared to the Original Forecasts. For 2023, the increases are primarily in the Transmission Sustainment and the Stations Sustainment portfolios, with FBC proposing to reduce the expenditures for the Distribution Sustainment and the Telecommunications portfolios to offset some of the required increases. For 2024, the increases are primarily in the Transmission Sustainment and Telecommunications portfolios, with FBC proposing to reduce the expenditures for the Distribution Sustainment and the Stations Sustainment portfolios to offset some of the required increases. These increases are described in Section 7.2.1.1.3 below.

7.2.1.1.3 DRIVERS OF UPDATED GROWTH AND SUSTAINMENT CAPITAL FORECASTS

The drivers of the increases in growth and sustainment capital are summarized as follows:

- Significant inflationary increases brought on by unanticipated events such as the COVID-19 pandemic and the war in Ukraine, which have resulted in large cost escalations in materials, labour and fuel;
- Increases in growth capital as a result of more customer applications; and
- Additional reliability, refurbishment or end of life projects being required that were not anticipated at the time of the MRP proceeding.

These cost drivers, as well as the mitigation efforts FBC has undertaken during the first three years of the MRP term, are described in the following subsections.

FBC is Experiencing Significant Inflationary Pressures

FBC's Original Forecasts were developed using an assumption of two percent for annual inflation. While FBC has generally managed its overall capital spending within the approved levels over the first two years of the MRP term, FBC has begun to experience pressures throughout its growth and sustainment portfolios. These pressures coincide with the significant global market events experienced during this time period, including the COVID-19 pandemic, supply chain disruptions, and the war in Ukraine. These unforeseen events have had a significant impact on market conditions for many commodities and services that make up FBC's supply chain, and the impacts are still being felt and continue to contribute to volatility in the supply chain and the overall commodity and services market in 2022.

In order to better understand the extent of the inflationary impacts that have affected North American utilities since 2020 and to compare the impacts on the industry with FBC's experience, FBC engaged Wood Mackenzie Supply Chain Consulting (Wood Mackenzie) to provide a market report on electric and gas utility transmission and distribution (T&D) markets from 2020 to 2022 and the anticipated impact until the end of 2024 (Wood Mackenzie Report). Wood Mackenzie identified an average escalation of 17.5 percent in capital costs for electric utilities between the period of the first quarter of 2020 and the first quarter of 2022. The Wood Mackenzie Report is based on the aggregated spend from utilities across North America, and incorporated over 150 indices which roll up to form the model for each category. Indices specific to BC have also been incorporated where appropriate, particularly around trades and other labour in the Province. This report has been included as Appendix C1.

FBC has experienced significant inflationary pressures during the first three years of the MRP term and expects these pressures will continue into 2023 and 2024. In particular, FBC has experienced the most significant inflationary cost pressures for poles, transformers and wires/cables. The projects in Transmission, Distribution and Station growth and sustainment portfolios have been impacted by incremental increases in the cost of these materials since 2020. Cost escalation is also impacting FBC due to steel commodity prices in North America, which have increased approximately 117 percent from the first quarter of 2020.

As shown in the Wood Mackenzie Report, it is expected that the average capital costs for electric utilities will continue to rise until the fourth quarter of 2024, although at a slower pace than what was experienced between the first quarter of 2020 and the first quarter of 2022, and will not come back down to the 2020 level. This expectation also aligns with the Bank of Canada's July 2022 Monetary Policy Report[37] which projects that CPI is expected to hover around 8 percent in the third quarter of 2022 before decreasing to approximately 3 percent by the fourth quarter of 2023 and 2 percent in 2024.

[37] https://www.bankofcanada.ca/wp-content/uploads/2022/07/mpr-2022-07-13.pdf.

Updated Forecasts Reflect Increased Growth

The New Connects category includes the installation of new electric services consisting of additions to FBC overhead and underground distribution facilities. These capital expenditures allow FBC to meet its obligation to provide reliable service to customers in its service area. This category also funds any costs associated with upgrading FBC facilities to provide service for an extension or drop service. Consistent with past practice, the forecast expenditures for New Connects are based on a historical rolling average of expenditures adjusted by inflation. The overall increase is due to more customer applications for connections.

Updated Forecasts Reflect New Growth and Sustainment Projects

As noted by the BCUC in the MRP Decision, there are inherent uncertainties in capital forecasting, particularly when forecasting projects over a five-year period. In the MRP Application, FBC identified projects over $1 million that it anticipated undertaking over the five-year MRP term. Due to a variety of reasons, such as land and permitting issues, re-prioritization of capital spending, and changes in capacity requirements, some projects have been delayed or cancelled while other new projects have been identified and prioritized.

For example, in order to address aging infrastructure and to support load growth while maintaining current levels of reliability, substation rebuild projects or transformer addition projects are required. In some cases, these projects require increasing the station footprint and acquiring more adjacent land or larger parcels of land in new locations. The selection of an appropriate land parcel can be a lengthy process that can include activities such as open houses as part of stakeholder consultation. Given the uncertainties related to consultation and purchase negotiation, it introduces risk to project timelines if these activities are not completed in advance of the project execution window. The need to acquire land has arisen in a number of FBC's planned projects and has resulted in increased costs and, at times, delays to the project schedule. Projects that have been impacted by land acquisition requirements are described in Appendix C2 and include, as an example, the Fruitvale Station Upgrade project.

As detailed in the MRP Application[38], FBC actively manages its capital plan to ensure projects are planned and executed efficiently. Accordingly, the timing, scope, and cost of the individual projects and programs within the overall regular capital forecasts are subject to change, and FBC may identify new projects and programs that need to be added over the term of the MRP. The capital plan contains a mix of projects across the portfolio categories, some of which are time sensitive and others that have some schedule flexibility. The plan is developed with the understanding that conditions change and the plan must be capable of adapting. This provides FBC flexibility to manage and execute normal levels of unforeseen urgent work that are expected to occur throughout the year within the resource and budget constraints of the capital plan. While this flexibility means that individual projects may move around, at a portfolio level, FBC has consistently executed a similar portfolio of work to the Original Forecasts.

[38] Section 3.4.1.5, page C-106.

In Appendix C2, FBC provides a list of the projects over $1 million which are included in the Updated Forecasts for 2023 and 2024.

FBC Employed Mitigation Strategies to Limit Cost Pressures

FBC has implemented the following strategies to mitigate the impact of the aforementioned cost pressures:

- Re-scheduling projects that can be safely re-scheduled to 2023 to accommodate other project costs increase that could not be deferred. As detailed in Section 3.2 (Capital Planning Process – page C-52) of the MRP Application, FBC manages its capital investment plan to maintain a safe and reliable system, optimize resources and spending, and achieve efficiencies and cost savings. The capital plan contains a mix of projects, some of which are time-sensitive and others that have some schedule flexibility. The plan is developed with the understanding that conditions change, and the plan must be capable of adapting. This provides FBC flexibility to manage and execute normal levels of unforeseen urgent work that is expected to occur throughout the year within the resource and budget constraints of the capital plan. While FBC has delayed some work with flexible timing to accommodate the increased demands in 2022, this has only mitigated part of the capital pressures due to the magnitude of market pressures;
- Entering into long-term supply contracts for many commonly used materials and service providers (e.g., engineering consultants, construction contractors, etc.);
- Competitively tendering large contracts for materials and services to ensure competitive pricing;
- Communicating with critical suppliers and contractors to discuss issues and mitigation strategies;
- Negotiating collective agreement with unionized FBC employees that provide longer-term stability for internal labour rates (IBEW and MoveUP agreement expires in 2023); and
- Optimally allocating construction work to internal or external construction crews as appropriate.

Despite the mitigation strategies listed above, FBC has not been able to fully mitigate cost increases due to the cost drivers described above.

7.2.1.2 Other Capital

In this section, FBC provides its Updated Forecasts for other capital. Other capital includes Equipment, Facilities and Information System (IS) expenditures.

Table 7-8 below shows the Approved and Actual/Projected other capital from 2020 to 2022 while Table 7-9 below shows the Original and Updated Forecasts of other capital for 2023 and 2024. FBC notes that the majority of the increase shown in the Updated Forecasts is related to Facilities, primarily as a result of the Kelowna Space Project.

Table 7-8: Approved and Actual/Projected Other Capital Expenditures 2020-2022 ($ millions)

Line No.	Description	2020 Approved	2020 Actual	2021 Approved	2021 Actual	2022 Approved	2022 Projected
1	Equipment	3.407	3.444	3.338	2.711	3.274	3.560
2	Facilities	3.264	3.434	2.346	3.685	2.346	2.846
3	Information Systems	9.081	9.158	9.028	8.953	9.136	9.975
4	Total Other Capital	15.752	16.036	14.712	15.349	14.756	16.381

Table 7-9: Original and Updated Forecasts of Other Capital Expenditures 2023 and 2024 ($ millions)

Line No.	Description	2023 Original Forecast	2023 Updated Forecast	2024 Original Forecast	2024 Updated Forecast
1	Equipment	3.681	4.099	3.388	3.717
2	Facilities	2.346	4.305	2.346	4.096
3	Information Systems	9.254	9.254	9.400	9.400
4	Total Other Capital	15.281	17.658	15.134	17.213

The following sections provide further details on the Updated Forecasts for other capital.

7.2.1.2.1 EQUIPMENT CAPITAL

Equipment capital expenditures include the acquisition of vehicles, specialized tools and equipment. Expenditures for the equipment listed above are driven by obsolescence, excessive wear and regulatory compliance.

FBC's 2023 and 2024 capital forecasts for Equipment have increased by $0.418 million and $0.329 million, respectively, compared to the Original Forecasts. The average unit cost per vehicle has risen significantly as supply of vehicles has reduced in relation to demand in the marketplace. In particular, FBC is experiencing the following changes to the average cost of the vehicles:

- Substantial reduction in volume-based concessions from manufacturers to all commercial fleet (from $10.5 thousand to $2.5 thousand per unit);
- Increased costs on steel, aluminum, glass and paint; and
- Inflationary surcharges on transport of materials, services and labour by manufacturers;

7.2.1.2.2 FACILITIES CAPITAL

Facilities capital expenditures include the acquisition or leasing of land, buildings, and building equipment. Facilities capital expenditures focus primarily on capacity planning, upgrading and replacement of end of life assets. The Facilities department ensures approved facilities projects are built to meet internal standards, building codes and regulations, and provide a long-term solution toward meeting the business requirements.

As shown in Table 7-9 above, FBC's 2023 and 2024 Facilities capital forecasts have increased by $1.959 million and $1.750 million in 2023 and 2024, respectively, compared to the Original

Forecasts. As further explained below, the majority of the increase is for the Kelowna Space Project. The remainder of the increase is related to: (i) energy management and GHG emissions reductions activities that FBC is planning to undertake to improve the adaptability and resiliency of FBC's facilities; and (ii) the installation of EV infrastructure at FBC's facilities.

Kelowna Space Project

FBC continues to experience capacity challenges at numerous locations for office, material storage and parking spaces and has been working to address these complex challenges. These capacity issues are impacting FBC's facilities across the Province and require different solutions depending on the location, as the challenges vary depending on the unique circumstances of each region. At the time of filing the MRP Application, FBC was in the process of developing a strategy for a cost-effective solution to the capacity issues in the Kelowna area, and therefore did not include this project in its Original Forecasts.

Both FEI and FBC have been experiencing space capacity challenges in the Kelowna region. Identifying solutions to address the space constraints has been very challenging, particularly due to the significant escalation in real estate costs to acquire new industrial land in the Kelowna area. However, the companies have now finalized a solution which leverages the use of FEI's and FBC's existing sites and results in the leasing of a new site for FEI's and FBC's Shared Services Departments. As further explained below, the Kelowna Space Project is a combined project for FEI and FBC, and the cost of the project has therefore been allocated between the two utilities accordingly. The total cost of the Kelowna Space Project is $13.930 million. Of this total, approximately $2.934 million is allocated to FBC based on employee count, with $1.209 million and $1.000 million reflected in FBC's Updated Forecasts for 2023 and 2024, respectively[39].

As part of the Kelowna Space Project, both FEI and FBC Shared Services Departments (Support Services) located in Kelowna will relocate to a new office lease facility approximately 25,000 ft^2 in size. Tenant improvements will be completed in 2023 and the Shared Services Departments will be relocated to this new leased facility. The allocation of leasing costs for this site will be determined using a cost driver approach based on the number of employees for FEI and FBC. In addition, FBC's Electrical Operations will move to the existing FEI-owned Springfield facility, as that location has a larger footprint and thus better aligns with the required Electrical Operations Space Program. FEI's Gas Operations will move to the existing FBC-owned Benvoulin property, as Gas Operations has a smaller footprint requirement. Broadly speaking, the Electrical and Gas Operations will "swap" locations.

Each building will require modifications to accommodate the Space Program requirements. Work will commence in late 2023 to complete the swap in 2025. Changes in building occupancy will be captured through new lease agreements where FEI will lease the entire Benvoulin building from

[39] There was also approximately $0.631 million and $0.094 million of actual costs related to the Kelowna Space Project allocated to FBC in 2020 and 2021, respectively, with the total allocation to FBC equaling approximately $2.934 million, including the forecast expenditures in 2023 and 2024.

FBC and FBC will lease the entire Springfield building from FEI. The buildings will remain operational while these changes are made.

The Kelowna Space Project results in a number of benefits for both FEI and FBC, including:

- Provision of sufficient space for both Operations and Support Services:
  - Support Services space requirement of 25,000 ft^2 of office at a new leased facility;
  - Gas Operations space requirement of 15,000 ft^2 of office and 12,000 ft^2 of industrial storage and shop space align with the sizing of the Benvoulin buildings and site; and
  - Electric Operations space requirement of 33,000 ft^2 of office and 13,000 ft^2 of industrial storage and shop space align with the sizing of the Springfield buildings and site;
- Retaining and updating the existing properties and adding a leased office facility results in a reasonable implementation timeline; changes are made at a measured pace to minimize business and employee disruption and do not require temporary relocation to another facility;
- The solution ensures Electric Operations remain located in an area that best supports their service territory; by not relocating this group farther from the city, potential inefficiencies are prevented;
- The solution is cost effective in contrast to other options such as purchasing new property or constructing a new Operation Hub, and utilizes FEI's and FBC's existing properties to the best extent possible; and
- Each Operations group is located in its own facility, increasing planning, operations, and management efficiencies.

Capital Expenditures to Support Energy Efficiency and GHG Reductions

The Updated 2023 and 2024 Forecasts include $0.750 million in each year for expenditures that are specifically in support of energy efficiency and GHG emissions reductions. These expenditures consist of projects that will result in reduced electrical and natural gas usage in FBC's facilities and/or will result in GHG emissions reductions. Where applicable, the planned projects are aligned with the ISO 50,001 Energy Management Standard, and enable FBC to prepare for the impacts of climate change and the transition to net-zero emissions. These planned projects will improve FBC's buildings' energy efficiency, support the adoption of electric vehicles, and contribute to efforts towards climate change and the Province's CleanBC Plan targets.

FBC is pursuing energy management and GHG emissions reduction opportunities for its buildings as part of the Company's climate action initiatives, including energy management activities related to climate adaptation, mitigation, and resiliency for buildings. FBC also plans to install EV charging infrastructure at FBC's facilities for fleet use.

Historically, the Facilities department has prioritized capital spending for capacity planning, end-of-life replacements, and meeting building codes and regulations. However, in light of the importance of addressing climate change, Facilities is now focusing on advancing climate action initiatives and strategies. Examples of advancements are installation of EV charging infrastructure, upgrading lighting to LED, completing energy audits to identify opportunities to inform capital planning, and incorporating energy efficiency components in long-term lease agreements.

7.2.1.2.3 INFORMATION SYSTEMS

FBC's Information Systems (IS) expenditures focus on enhancing, replacing, upgrading and sustaining existing applications and infrastructure or, as needed, introducing new technology capabilities in order to improve safety, customer service, reliability and efficiency.

As shown in Table 7-8 above, the actual/projected expenditures for 2020 through 2022 are generally consistent with what was forecast in the MRP Application. As such, FBC has not made any changes to the 2023 and 2024 IS capital forecasts (Table 7-9 above) compared to what was presented in the MRP Application as there have been no changes in circumstances or anticipated spending that would warrant revisions.

7.2.1.3 Summary of FBC's Updated Regular Capital for 2023 and 2024

FBC provided an updated forecast for regular growth, sustainment and other capital in 2023 and 2024. These Updated Forecasts are summarized in Table 7-10 below.

Table 7-10: Summary of 2023-2024 Updated Forecasts of Regular Capital

Line No.	Description	2023 Updated Forecast	2024 Updated Forecast
1	Growth Capital	30.973	24.568
2	Sustainment Capital	45.797	58.673
3	Other Capital	17.658	17.213
4	Total Regular Capital	94.428	100.454

For FBC's growth and sustainment capital, the Updated Forecasts reflect the significant and unanticipated cost pressures experienced over recent years. These pressures, generally experienced by North American utilities, are being driven by factors outside of FBC's control, and include, among others, the COVID-19 pandemic, supply chain pressures and the war in Ukraine, as well as growth-related expenditures and necessary reliability, refurbishment and end of life replacement projects. The Updated Forecasts will ensure FBC's ability to execute its planned growth and sustainment capital programs which are critical to ensuring the ongoing safe and reliable operation of FBC's system and ensuring that FBC is able to meet its customer's needs.

For FBC's other capital, the Updated Forecasts are primarily related to the Kelowna Space Project, as well as expenditures for activities at FBC's facilities related to energy efficiency and GHG emissions reductions.

7.2.2 Flow-Through Capital Expenditures

FBC is afforded flow-through treatment for certain capital items due to a variety of factors, including their uncontrollable nature, because they drive incremental revenues, because they are related to Clean Growth initiatives, or because of the uncertainty in scope, costs and timing. The amounts for 2023 are shown in Table 7-11 below along with a comparison to 2022.

Table 7-11: Flow-Through Regular Capital Expenditures ($ millions)

Line No.	Description	Approved 2022	Projected 2022	Forecast 2023	Reference
1	Clean Growth Initiative - EV DCFC	$ -	$ 1.560	$ 0.248	
2	Exogenous Factor - MRS	0.935	0.870	-	
3	Forecast Capital Expenditures	$ 0.935	$ 2.430	$ 0.248	Section 11, Schedule 4, Line 10

7.2.2.1 EV DCFC Stations

As discussed in Section 5.8, FBC's EV DCFC stations are prescribed undertakings under section 5 of the GGRR[40], and the cost of service associated with EV charging stations is subject to flow-through treatment. Please refer to Table 5-2 of Section 5.8 which provides a summary of the EV DCFC stations' costs and revenues from 2021 Actual to 2023 Forecast.

Table 7-11 above shows the EV DCFC stations capital expenditures for 2022 Approved[41], 2022 Projected, and 2023 Forecast. FBC originally did not forecast any EV DCFC station capital in 2022 during the 2022 Annual Review as FBC expected all construction activities to be completed in 2021. However, the originally planned construction activities in 2021 were delayed to 2022 mainly due to the flooding experienced in the latter part of 2021 which also led to FBC being required to undergo design changes to 16 of its DCFC sites to complete a required safety retrofit for the power supply kiosks. The flooding caused delays in construction and deployment for two planned DCFC stations in Keremeos and Princeton that were identified in FBC's Revised and Updated Application for EV DCFC Service and approved by Order G-215-21[42]. This resulted in an increase in capital expenditures for 2022 Projected when compared to 2022 Approved. FBC notes the reduction in expenditures for 2021 due to the delayed deployment of the Keremeos and Princeton stations was offset by the installation of two new DCFC stations in late 2021 at existing sites (i.e., Naramata and Grand Forks). Installations at Keremeos and Princeton are planned to be completed by the end of 2022, which by then will bring the total number of DCFC stations in service to 42 across the 23 sites. At this time, FBC is not expecting to construct any additional

[40] Order G-215-21 dated July 14, 2021.
[41] Consistent with the 2022 Annual Review Decision, FBC included the 2022 forecast revenues and expenses associated with the EV DCFC stations in the Compliance Filing to the Annual Review Decision and Order G-374-21 because approval of the EV DCFC Service Application was not received until November 24, 2021. Accordingly, the 2022 Approved amount reflected in Table 7-11 is the amount included in the Compliance Filing.
[42] FBC's Revised and Updated EV DCFC Service Application, Table 2-2, pp. 10-11.

stations or sites beyond the two additional DCFC stations noted above; however, station utilization will continue to be monitored to determine if any additional stations are warranted to meet customer demand. For 2023, FBC is forecasting to complete accessibility improvements for its existing EV DCFC sites. These improvements include new or additional lighting as the stations are available for use 24 hours a day, and paving for wheelchairs access to the charger.

The two new DCFC stations were installed at the existing Naramata and Grand Forks sites that only have a single DCFC station installed previously. Both Naramata and Grand Forks were identified in FBC's Revised Application for EV DCFC Service, and construction of these two additional stations was completed in late 2021. As directed by Order G-341-21[43], FBC is to include evaluation of any additional EV charging stations that were not originally identified in the Revised EV DCFC Service Application in FBC's Annual Review process, including review of whether the additional stations meet the criteria to be a prescribed undertaking under the GGRR and assessment of whether the levelized rate under RS 96 EV DCFC service will need to be recalculated as a result of the additional EV charging stations. Consistent with the information provided in FBC's Revised EV DCFC Application, Table 7-12 below shows that these two additional stations are prescribed undertakings and meet the requirements as set out in section 5 of the GGRR. Regarding the review of the levelized rate under RS 96 EV DCFC service, as discussed in Section 5.8, FBC is required to file a detailed assessment of the EV DCFC service by the end of December 31, 2022, which includes an update of the financial models with actual and forecast information as well as a detailed assessment of RS 96 and alternative rate design options. For the purposes of regulatory efficiency, FBC will address the review of the levelized rate under RS 96 EV DCFC service in the assessment report.

Table 7-12: Assessment of New EV DCFC Stations as Prescribed Undertakings Under the GGRR

	Greenhouse Gas Reduction Regulation Criteria						
GGRR Section	5(1)(a)	5(1)(b)	5(1)(c)	5(2)(a)	5(2)(b)(i)	5(2)(a)(ii)	5(2)(c)
	Station is available for use 24 hours a day by any member of the public	Station does not require users to be members of a charging network	Station is capable of charging electric vehicles of more than one make	Eligible charging station is constructed and operated or purchased and operated by the public utility	The public utility reasonably expects, on the date the public utility decides to construct or purchase an eligible charging station, that		For any eligible charging station coming into operation on or after January 1, 2022, the station uses or is configured to use the Open Charge Point Protocol.
					The station will come into operation by December 31, 2025. (Operation Date)	Is the station located in a limited municipality? (Population – 2021 Census)	
Sites							
Naramata	Yes	Yes	Yes	Yes	Q4 2021	No[1]	Yes
Grand Forks	Yes	Yes	Yes	Yes	Q4 2021	No (4,112)	Yes

[43] Decision and Order G-341-21, p. 27.

Note to Table:

[1] Not located in a municipality as defined by the Community Charter.

7.2.2.2 Mandatory Reliability Standards Incremental Capital

As explained in Section 6.3.5, the incremental capital expenditures related to the adoption of MRS AR13 were approved for exogenous factor treatment in the 2022 Annual Review Decision. These costs are for the implementation of changes/additions, including the development and implementation of methods to monitor network traffic and software tools to support the changes/additions to the standards. The implementation of the required changes/additions requires the purchase and installation of hardware and software to assess and evaluate network traffic and the development of software tools to track risk assessments of any product or service procured for Bulk Electrical System assets.

Table 7-13 below shows the incremental capital expenditures related to MRS AR13 with a breakdown between labour, non-labour and contingency for 2022 Approved, 2022 Projected and 2023 Forecast.

Table 7-13: Incremental Capital Expenditures for MRS AR13 ($ millions)

Line No.	Description	Approved 2022	Projected 2022	Forecast 2023	Reference
1	Labour	$ 0.580	$ 0.680	$ -	
2	Non-Labour	0.205	0.140	-	
3	Contingency	0.150	0.050	-	
4	Total	$ 0.935	$ 0.870	-	Section 11, Schedule 4, Line 8

As shown in the table above, the 2022 Projected capital expenditures are approximately $0.065 million less than 2022 Approved. The reason for the variance is that FBC was able to purchase some software early (i.e., at the end of 2021 instead of 2022). Overall, there is no change to the original total estimate of $0.935 million (i.e., $0.065 million in 2021 Actual and $0.870 million in 2022 Projected).

As explained in the 2022 Annual Review[44], FBC is not expecting any incremental capital costs for 2023; therefore, the 2023 Forecast is zero. As the capital expenditures related to MRS AR13 are approved for flow-through treatment, any variances from Projected and Forecast amounts for the adoption of MRS AR13 will be trued up by way of the Flow-through deferral account and returned to, or recovered from, customers in future years.

7.3 MAJOR PROJECTS CAPITAL EXPENDITURES

Major Projects are capital expenditures that do not form part of regular capital spending as they are approved through a separate CPCN or other application. As part of the MRP Decision,[45] the

[44] Exhibit B-3, BCUC IR1 24.2.
[45] MRP Decision and Order G-166-20, pp. 132-133.

BCUC approved the continuation of the current process of reviewing Major Projects outside of the proposed MRP and approved the continuation of the existing financial threshold for CPCNs of $20 million for FBC for the MRP term.

For 2023, FBC is forecasting capital expenditures related to the KBTA project only. However, FBC's 2023 Forecast rate base also includes the full-year impact of capital additions related to the Corra Linn Dam Spillway Gate Replacement project, the UBO Old Units Refurbishment project, and the Playmor Substation Upgrade project, all of which are expected to complete in 2022. Each of these approved projects is described further below.

KBTA Project

The KBTA project was approved by Order C-4-20 and involves the installation of a third terminal transformer at the F.A. Lee Terminal Station, including the reconfiguration of the 138 kV bus into an industry standard ring bus configuration. The new transformer is scheduled to be in service by the end of 2022 or early 2023, with project close-out in 2023, at an estimated cost of $23.288 million, inclusive of AFUDC and cost of removal. FBC forecasts capital expenditures of $11.384 million and $1.710 million (excluding AFUDC) in 2022 and 2023, respectively, with $21.250 million to be added to rate base on January 1, 2023 and the remainder added to rate base on January 1, 2024.

Corra Linn Dam Spillway Gate Replacement Project

The Corra Linn Dam Spillway Gate Replacement project was approved by Order C-1-17 and involves the replacement of 14 spillway gates and upgrades to the associated infrastructure. The project is expected to be complete in 2022 at a cost of $79.727 million, inclusive of AFUDC and cost of removal. Thus, FBC is not forecasting any capital expenditures related to this project in 2023. Since 2020, a total of $51.768 million has been added to FBC's rate base with the remaining $16.151 million forecast to be added to rate base in 2023. Overall, $67.919 million is forecast to be added to rate base by January 1, 2023 ($51.768 million of actual from 2020 to 2022 plus $16.151 million of 2023 Forecast), plus $11.808 million of cost of removal, for a total estimated project cost of $79.727 million including AFUDC and cost of removal.

UBO Old Units Refurbishment Project

The UBO Old Units Refurbishment project was approved by Order G-8-17 and involves the refurbishment of four generating units that are more than 100 years old. The refurbishments were completed in 2021 at an estimated total project cost of $34.180 million, inclusive of AFUDC and cost of removal. FBC is projecting approximately $0.002 million of remaining close-out costs in 2022 which will be added to rate base January 1, 2023. Overall, $32.290 million is forecast to be added to rate base by January 1, 2023 ($32.288 million of actual from 2018 to 2022 and $0.002 million of 2023 Forecast), plus $1.890 million of cost of removal, for a total estimated project cost of $34.180 million including AFUDC and cost of removal. As directed by the BCUC in the Annual Review for 2017 Rates, the UBO Refurbishment Project Final Report is included as Appendix B2.

Playmor Substation Upgrade Project

The Playmor Substation Upgrade project was approved by Order G-42-21 and involves rebuilding the Playmor substation in South Slocan, BC on an expanded station footprint in order to increase station capacity. The project is expected to be complete in 2022 at an estimated cost of $8.036 million, inclusive of AFUDC, and approximately $0.300 million of cost of removal. As the project is expected to complete in 2022, FBC is not forecasting any capital expenditures related to this project in 2023, and all project costs, estimated to be $8.036 million (including AFUDC) are forecast to enter rate base on January 1, 2023, with $0.300 million to be recorded to cost of removal.

7.4 2023 PLANT ADDITIONS

The 2023 Plant Additions are comprised of: (i) FBC's 2023 regular capital expenditures from Section 7.2; (ii) the Major Projects from Section 7.3 to the extent that portions of those projects are placed into service; (iii) the change in work in progress which adjusts for capital expenditures for projects that are in progress at year-end; (iv) AFUDC; and (v) overhead capitalized for the year. A reconciliation of capital expenditures to plant additions is shown below and is also provided in Section 11, Schedule 5.

Table 7-14: Reconciliation of 2023 Capital Expenditures to Plant Additions ($ millions)

Line No.	Description		Forecast 2023	Reference
1	Forecast Capital Expenditures	$	94.428	Section 11, Schedule 5, Line 2
2	Flow-Through Capital Expenditures		0.248	Section 11, Schedule 5, Line 3
3	Total Gross Regular Capital Expenditures		94.676	Sum of Lines 1 and 2
4				
5	Capitalized Overhead		10.918	Section 11, Schedule 5, Line 16
6	AFUDC		0.243	Section 11, Schedule 5, Line 17
7	Change in Work in Progress		-	Section 11, Schedule 5, Line 19
8	Total Regular Additions to Plant		**105.837**	Sum of Lines 3 through 7
9				
10	Special Projects and CPCN Capital Expenditures			
11	Kelowna Bulk Transformer Capacity Addition		1.710	Section 11, Schedule 5, Line 7
12	AFUDC		0.049	Section 11, Schedule 5, Line 23
13	Change in Work in Progress		43.680	Section 11, Schedule 5, Line 25
14	Total Special Projects and CPCN Additions to Plant		**45.439**	Sum of Lines 11 through 13
15				
16	Total Plant Additions	**$**	**151.276**	Line 8 + Line 14

7.5 ACCUMULATED DEPRECIATION

Rate base includes both the accumulated depreciation on plant in service and accumulated amortization of CIAC. Both are increased through depreciation expense and decreased through retirements.

The depreciation rates used for 2023, which were approved by Order G-166-20 and are based on FBC's most recent depreciation study, include the recovery of the estimated future costs of removal over the average service life of the assets (net salvage) in accumulated depreciation. Depreciation is calculated beginning January 1 of the year after the assets are placed in service, which is the treatment approved by Order G-139-14.

Based on calculating depreciation expense at these approved depreciation rates on the opening plant-in-service balance, the 2023 depreciation expense is calculated as $64.407 million.[46]

7.6 *DEFERRED CHARGES*

On May 3, 2017, the BCUC issued its Regulatory Account Filing Checklist.[47] The stated purpose of the checklist is to assist regulated entities when filing regulatory account requests and to facilitate an efficient review by the BCUC.

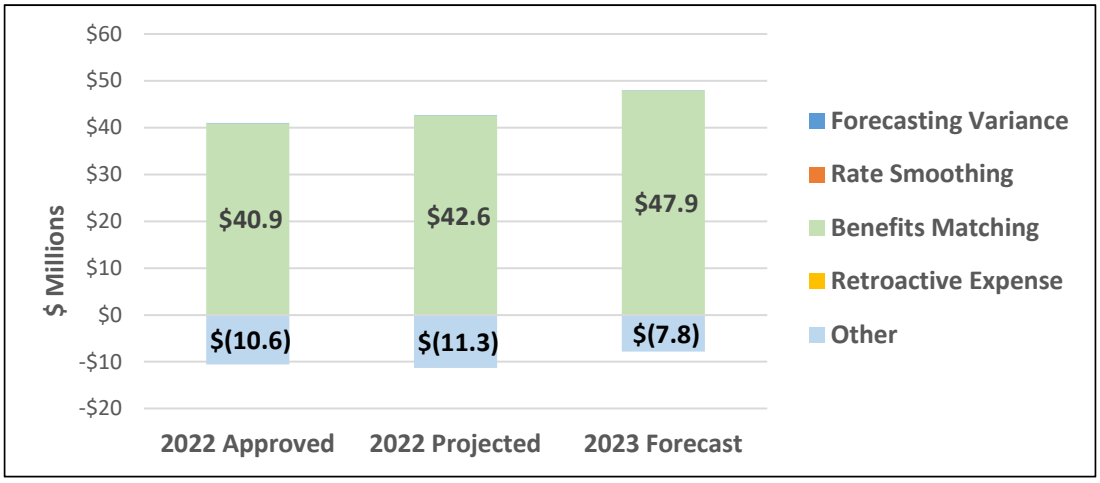
The checklist classifies deferral accounts as one of: (a) forecast variance account; (b) rate smoothing account; (c) benefit matching (capital-like) account; (d) retroactive expense account; or (e) other. In Section 11, Schedule 11, FBC has classified its rate base deferral accounts in accordance with this classification.

The 2023 Forecast mid-year balance of unamortized deferred charges in rate base for FBC is a debit of $40.045 million. The 2023 debit balance is driven largely by the balances in the Demand Side Management (DSM) and Deferred Debt Issue Costs deferral accounts, partially offset by the Pension and OPEB Liability deferral account.

Figure 7-1 provides the mid-year deferral account balances summarized by deferral account category.

[46] $69.474 million depreciation expense as shown in Section 11, Schedule 21, Line 2 less $5.067 million amortization of CIAC as shown in Section 11, Schedule 21, Line 8.
[47] BCUC Letter, Log No. 53608, Appendix B.

Figure 7-1: FBC Forecast Mid-Year Balances of Rate Base Deferral Accounts by Category



Based on amortizing the opening deferral account balances (rate base and non-rate base) using the approved and proposed amortization periods, the 2023 amortization expense is calculated as a credit of $3.277 million.[48] The subsections below include a discussion on new rate base deferral accounts and changes or updates to existing rate base deferral accounts. For a discussion on non-rate base deferral accounts, please refer to Section 12.

7.6.1 New Deferral Accounts

FBC is seeking approval to create one new rate base deferral account in this Application, as discussed below.

7.6.1.1 Joint Pole Use Audit 2023

Under the provisions of FBC's various joint use pole agreements, the parties are required to perform an audit of the joint use pole contacts once every five years, the last of which occurred in 2018.

Consistent with past treatment of costs for joint pole use audits, FBC is seeking approval to establish a rate base deferral account to capture costs incurred for the 2023 Joint Use Pole Audit, which are estimated at $0.435 million ($0.318 million after tax) to be incurred in 2023.

FBC is also requesting approval to amortize these costs over a five-year period beginning January 1, 2023, which represents the time period between the required audits.

Table 7-15 below addresses the considerations identified in the Regulatory Account Filing Checklist as they pertain to the above-described deferral account request.

[48] Section 11, Schedule 21, Column 3, Sum of Line 5 and 6.

Table 7-15: Deferral Account Filing Considerations

Item	Consideration	Joint Pole Use Audit 2023
I.	Indicate if the request is: (a) for a modification or a change in scope to an existing Commission approved regulatory account; or (b) to establish a new regulatory account.	The 2023 Joint Pole Use Audit deferral account is a new deferral account, consistent with the past treatment of joint pole use audits in previous years.
a)	If the request is for a modification or change in scope to an existing regulatory account, explain why the existing regulatory account is an appropriate account to use (specifically addressing the existing account's intended and approved purpose, mechanism for recovery, timeline for recovery and carrying costs).	N/A
b)	If the request is for approval of a new regulatory account, state the purpose of the regulatory account and explain its intended use.	The purpose of the requested account is to capture costs related to joint use pole audits that are required once every five years.
II.	Propose a term (i.e. length of time) that the regulatory account should be approved for and explain why that term is appropriate.	The term of the account encompasses the conduct of the audit and subsequent amortization period, equivalent to the term of the benefit.
III.	Identify any alternate treatments that were considered, including an overview of what the accounting treatment would be in the absence of approval of the request to establish a regulatory account, and explain why these alternate treatments may not be appropriate.	In the absence of a deferral account, the costs of the audit would have to be forecast as an O&M expense (outside of the MRP formula O&M since the 2018 audit costs were deferred and excluded from Base O&M Expense) and trued up annually by way of the Flow-Through deferral account. FBC considers a deferral account to be the more appropriate treatment since it permits the amortization of costs over the five-year period between audits.
IV a)	Address: whether, or to what extent, the item is outside of management's control;	An audit of joint use poles is required at five-year intervals as a condition of FBC's agreements with the counter parties and is therefore outside of FBC's direct control.
b)	the degree of forecast uncertainty associated with the item;	FBC forecasts audit costs based on past experience. Actual costs are recorded in the account so that the actual, not forecast, costs are recovered in rates.
c)	the materiality of the costs	Refer to Section 7.6.1.1.
d)	any impact on intergenerational equity	FBC proposes to recover the deferred costs over the five-year period between the required audits.
V.	Classify the regulatory account as either: (a) forecast variance account; (b) rate smoothing account; (c) benefit matching account; (d) retroactive expense account; or (e) other.	FBC classifies this account as a benefit matching account since the costs are recovered over the period between audits.
VI.	Identify if the regulatory account is a cash or non-cash account.	The joint use pole audit account is a cash account.

Item	Consideration	Joint Pole Use Audit 2023
VII.	Specify what additions to the regulatory account are being requested (i.e. type and amount of additions), including whether the account is intended to capture additions for a specific period of time or on an ongoing basis.	Costs include incremental labour, vehicle, and staff expense in addition to FBC's share of common costs such as data input costs. See Section 7.6.1.1.
VIII.	Propose a mechanism for recovery (e.g. how the balance in the regulatory account will be recovered or refunded to ratepayers) and explain why it is appropriate.	Costs are recovered in revenue requirements by way of amortization expense.
IX.	Propose a timeline for recovery (e.g. the period over which the regulatory account balance is either collected or refunded; also referred to as the amortization period) and explain why it is appropriate.	FBC proposes to recover the deferred costs over the five-year period between the required audits.
X.	Propose a carrying cost for the balance in the regulatory account and explain why it is appropriate.	Rate base deferral accounts are included in rate base and are therefore implicitly financed using the weighted average cost of capital (WACC).
XI.	Outline a recommended regulatory process for the Commission's review of the application.	The proposed deferral account can be reviewed as part of the present proceeding. Deferral account approvals and disposition are generally determined in revenue requirement proceedings. Where requested within CPCNs or other applications, the regulatory process will be included within the draft timetable for each specific application.

7.6.2 Existing Deferral Accounts

In the discussion below, FBC provides information on two existing deferral accounts and requests approval of an amortization period for one of them.

7.6.2.1 COVID-19 Customer Recovery Fund Deferral Account

7.6.2.1.1 DESCRIPTION AND FINANCIAL ESTIMATES

In June 2020, FBC received approval through Order G-133-20 to establish the COVID-19 Customer Recovery Fund Deferral Account in rate base to record three items:

1. any bill payment deferrals provided to customers due to the COVID-19 pandemic and subsequent payments of those deferred amounts;
2. any bill credits provided to customers due to the COVID-19 pandemic; and
3. any unrecovered revenue resulting from customers being unable to pay their bills due to the COVID-19 pandemic, which will be tracked separately by rate schedule.

The following section provides 2022 and 2023 financial estimates and descriptions for each of the three items approved for inclusion in the COVID-19 Customer Recovery Fund Deferral Account. FBC also proposes to commence amortization of the deferral account balance in 2023 and to discontinue quarterly reporting.

(a) Bill payment deferrals provided to residential and small commercial customers

The bill payment deferral program was offered to residential and small commercial customers affected by the COVID-19 pandemic. FBC experienced high collection rates in regard to this program, recovering approximately 85 percent of the outstanding balances through the regular monthly instalments. The remaining customer balances that were ultimately deemed unrecoverable have been designated as unrecoverable revenue and as such, a total of $0.119 million has been transferred to the COVID-19 Customer Recovery Fund Deferral Account. These additions to the deferral account are forecast in section (c), Table 7-18 *Unrecoverable Revenue Amounts*.

FBC ceased accepting new applications effective June 1, 2021 and is therefore not forecasting further additions related to this relief measure.

Table 7-16: Bill Payment Deferral Forecast Amounts ($ millions)

	2020 Actual	2021 Actual	2022 Projected	2023 Forecast
Opening Balance	-	0.563	0.005	-
Additions	0.803	-	-	-
Repayments	(0.240)	(0.444)	-	-
Transfers	-	(0.114)	(0.005)	-
Ending Balance	0.563	0.005	-	-

(b) Bill credits provided to small commercial customers

The bill credit program offered to small commercial customers has been calculated using the existing balance of $0.132 million as of April 2022. Given the duration and period these credits were available for, as well as the June 1, 2021 closure of the program for new applications, FBC does not expect additional credits to be offered to customers throughout the remainder of 2022 or in 2023. As such, FBC is proposing to amortize the $0.132 million over three years, with the 2023 amortization amount shown in Table 7-17 below.

Table 7-17: Bill Credit Amounts ($ millions)

	2020 Actual	2021 Actual	2022 Projected	2023 Forecast
Opening Balance	-	0.130	0.132	0.132
Additions	0.178	0.003	-	-
Tax	(0.048)	(0.001)	-	-
Amortization[49]	-	-	-	(0.044)
Ending Balance	0.130	0.132	0.132	0.088

[49] Based on a requested three-year amortization period, as discussed in Section 7.6.2.1.2.

(c) Unrecovered revenue resulting from customers being unable to pay their bills due to the COVID-19 pandemic

This portion of the deferral account forecast represents the amount of customer balances owing (i.e., account receivables) that are recognized as unrecoverable due to the COVID-19 pandemic. As such, these amounts are in excess of the normal course forecast bad debt expense that is recognized in indexed-based O&M.

Table 7-18: Unrecoverable Revenue Amounts ($ millions)

	2020 Actual	2021 Actual	2022 Projected	2023 Forecast
Opening Balance	-	0.011	0.134	0.375
Transfers[50]	-	0.114	0.005	-
Additions[51]	0.015	0.054	0.325	-
Tax	(0.004)	(0.045)	(0.089)	-
Amortization[49]	-	-	-	(0.125)
Ending Balance	0.011	0.134	0.375	0.250

The unrecovered revenue recorded in the deferral account includes:

- any remaining balances associated with the bill payment deferral program, described in section (a), that resulted from customers' inability to pay (shown as the Transfers line in Table 7-18 above); and
- any unrecovered revenue from all customer classes due to the COVID-19 pandemic, including industrial and large commercial customers and those residential and small commercial customers that did not participate in the bill payment deferral or bill credit relief offerings (shown as the Additions line in Table 7-18 above).

The 2022 Projected transfers of $0.005 million represent the actual 2022 transfers for the months available and any remaining bill payment deferral loan balances that were not yet repaid. The 2022 Projected additions of $0.325 million have been calculated using actual additions for the months available with the remainder of the year forecast using an approach consistent with the prior year. That is, a factor of 15 percent has been applied to the total outstanding balance of customer accounts that are past due as at March 1, 2022. This approach was based on a pilot outreach program in 2021 where 15 percent of customers with an average balance of $800 confirmed that they were financially impacted by the COVID-19 pandemic and required support to bring their account into good standing.

[50] The actual 2021 unrecoverable revenue transfers of $0.114 million consist of $0.004 million of small commercial customer balances and $0.110 million of residential customer balances.

[51] The actual 2020 unrecoverable revenue additions of $0.015 million consist of $0.014 million of small commercial customer balances and $0.001 million of residential customer balances. The actual 2021 unrecoverable revenue additions of $0.054 million consist of $0.004 million of small commercial customer balances and $0.050 million of residential customer balances.

While the forecasts of the unrecovered revenue additions above rely on estimates and broader macroeconomic factors, the actual amounts that will be recorded in the deferral account will reflect actual balances that are attributable to specific customers that cannot make payment due to the COVID-19 pandemic.

In this regard, to support the development of a consistent and appropriate approach for identifying amounts deemed unrecoverable due to COVID-19, FBC has created an internal set of guidelines to be used by members of the customer service team with an objective to identify and support customers that have been financially impacted by the COVID-19 pandemic. The underlying goal and intent of this approach is for customers to be able to maintain their gas services while maximizing recoveries associated with any balances due. These internal guidelines include questions that help identify the extent to which the customer has been impacted by COVID-19 as well as payment arrangement guidelines that include partial or full recognition of receivable balances as unrecoverable due to the COVID-19 pandemic.

7.6.2.1.2 DISPOSITION OF DEFERRAL ACCOUNT

As indicated in the 2022 Annual Review, additions to the COVID-19 Customer Recovery Fund Deferral Account for unrecovered revenues resulting from customers being unable to pay their bills due to the COVID-19 pandemic were expected to continue into 2022. As such, FBC has continued to capture unrecovered revenues in this deferral account during 2022.

Since the 2022 Annual Review, conditions have improved such that most COVID-19 pandemic restrictions in BC have been lifted.[52] The Federal government support programs such as the Canada Emergency Response Benefit (CERB) and the Canada Emergency Wage Subsidy (CEWS) for businesses have ended as the impact of the COVID-19 pandemic lessens. This, along with the improved economic conditions, although somewhat tempered recently with inflationary and recessionary considerations, suggests that ongoing pandemic support is not needed anymore.

Additionally, FBC has resumed most of its collection practices in 2022 with no significant uptick in unrecoverable revenues from customers experienced so far, and FBC anticipates full resumption of normal collection practices by mid-2022.

As a result, based on the positive current outlook for the COVID-19 pandemic and the lessened impact, FBC does not anticipate any further additions to the deferral account after 2022 and proposes to commence amortization of the balance in the deferral account on January 1, 2023 using a three-year amortization period. FBC considers a three-year amortization period to be appropriate because it matches the number of years during which the COVID-19 Customer Recovery Fund Deferral Account was active (i.e., 2020 through 2022).

Should public health and economic conditions deteriorate significantly due to the resurgence of the COVID-19 pandemic later this year or in the future (i.e., another wave of the pandemic which causes shutdowns and job losses impacting individuals and businesses), FBC may seek BCUC

[52] See Section 12.2.1 for further discussion and details.

approval again for deferral account treatment for the same purpose and reasons set out in the 2020 application.

7.6.2.1.3 REQUEST TO DISCONTINUE REPORTING

FBC seeks approval to discontinue the existing quarterly reporting requirements for the COVID-19 Customer Recovery Fund Deferral Account filed with the BCUC. If approved, the final quarterly report would be for Q4 2022 and would be submitted in Q1 2023.

With more than two full years of reporting complete, the closure of the deferral and credit program to new applicants as of June 1, 2021, and the planned discontinuation of additions to the deferral account as of December 31, 2022, FBC does not see further value in providing separate detailed reporting for this account.

7.6.2.2 Indigenous Relations Agreement (Huth Substation)

As part of the Annual Review for 2020 and 2021 Rates Decision and Order G-42-21, FBC received approval to establish the Indigenous Relations Agreement (Huth Substation) deferral account to capture costs to address the Penticton Indian Band's (PIB) concerns regarding the Huth Substation in Penticton and the impacts the substation has had on Syilx[53] history and culture, such as the discovery of ancestral remains found at the Huth substation while performing construction works.

The Huth substation is a vital component of the South Okanagan area power system, providing direct service to both FBC customers and the municipal utility of the City of Penticton. This hub is connected to five major transmission lines (42L, 49L, 47L, 52L and 53L) and to two City of Penticton distribution substations. Given the importance of the substation to the supply of power in the South Okanagan and the historical value of the land to the PIB and the Syilx people, FBC has engaged in reconciliation efforts with the PIB, consistent with the recent legislation passed by the Provincial government.

FBC stated in the 2020-2021 Annual Review that it would update its progress with respect to this matter in future annual reviews and request approval for recovery of costs captured in this deferral account once an agreement with the PIB had been reached and the impacts could be communicated.

FBC has been unable to continue preliminary discussions with the PIB on reconciliation efforts on the Huth substation. Due to impacts on the community from the COVID-19 pandemic, followed by the unique circumstances that arose in 2021 with the Kamloops Residential School findings, and as the Penticton Indian Band and FortisBC Energy Inc. are currently in discussions regarding the proposed Okanagan Capacity Upgrade project, FBC chose not to pursue further efforts regarding the Huth Substation until both parties agreed to proceed. FBC will continue to provide updates on this matter and on the deferral account in future annual review filings.

[53] The PIB is a community of the Syilx people.

7.7 WORKING CAPITAL

The working capital component of rate base is comprised of cash working capital and other working capital.

Cash working capital is defined as the average amount of capital provided by investors in the Company to bridge the gap between the time expenditures are required to provide service (expense lag) and the time collections are received for that service (revenue lag). The cash working capital requirements that have been included reflect the most recent Lead Lag Study results, as approved through Order G-166-20.

Other working capital includes customer (DSM) loans, employee loans and withholdings, and inventory of materials and supplies. 2023 amounts are forecast based on 2021 Actual levels.

7.8 SUMMARY

FBC's rate base includes the impact of regular and Major Project capital expenditures, adjusted for work-in-progress, AFUDC and overheads capitalized. FBC has provided forecasts for all of its rate base deferral accounts in the financial schedules included in Section 11. In Section 7.2.1, FBC requested approval of its updated 2023 and 2024 regular capital (growth, sustainment and other) forecasts; in Section 7.6.1, FBC requested approval of one new deferral account; and in Section 7.6.2, FBC discussed two existing accounts, including requesting amortization of one of these existing accounts. Finally, the rate base includes cash and other working capital.

8. FINANCING AND RETURN OF EQUITY

8.1 INTRODUCTION AND OVERVIEW

FBC has prepared this Application using a capital structure of 60 percent debt and 40 percent equity and a Return on Equity (ROE) of 9.15 percent as approved by Orders G-129-16 and G-47-14. FBC's ROE is set at a premium of 40 basis points over the benchmark ROE, which is the ROE approved for FEI.

FBC is currently participating in the BCUC-initiated Generic Cost of Capital (GCOC) proceeding and has filed evidence on its recommended capital structure and ROE as part of Stage 1 of the proceeding. In Order G-156-21 and accompanying Reasons for Decision, the BCUC found that the effective date to implement a new cost of capital will depend on the timing and progress of the GCOC proceeding. As explained in Section 1.2, FBC is seeking approval of interim 2023 rates pending the outcome of Stage 1 of the GCOC proceeding as well as a decision on FBC's 2023-2027 DSM Expenditure Plan. When a decision is reached on these proceedings, FBC will update its rate calculations and apply for permanent 2023 rates.

The 2023 Forecast for financing costs, including the interest expense on issued long- and short-term debt and on new issuances that are forecast, has been updated as described in Section 8.3 below. Based on the updated financing costs, FBC's AFUDC rate for 2023 (which is equal to its after-tax weighted average cost of capital) is 5.73 percent. Any variances from interest rates used to set rates, and any variances in interest resulting from items subject to flow-through in the Flow-through deferral account, will be flowed through to customers. All other differences in interest expense will affect the achieved ROE and be subject to earnings sharing.

8.2 CAPITAL STRUCTURE AND RETURN ON EQUITY

The Company finances its investment in rate base assets with a mix of debt and equity, as approved by the BCUC from time to time. Order G-47-14 approved a capital structure for FBC of 60.0 percent debt and 40.0 percent equity with an equity risk premium of 40 basis points over the benchmark ROE, which was set at 8.75 percent by Order G-129-16; these approved capital structure and ROE values have been used to calculate rates in the Application.

8.3 FINANCING COSTS

Debt financing costs include the borrowing costs on issued debt as well as on new issuances that are forecast. Debt consists of both long- and short-term debt.

8.3.1 Long-Term Debt

FBC is both a private and public issuer of long-term debt. In March 2022, FBC issued long-term debt of $100 million at a rate of 4.16 percent for a term of 30 years. The net proceeds were used to repay existing indebtedness and finance the Company's capital expenditure program. FBC

plans to issue additional long-term debt of approximately $75 million in 2023 and will use the funds for the same purposes. The 2023 debt issuance is reflected in the financial schedules in July 2023 at a rate of 4.90 percent.[54] The exact timing, amount and rate of the 2023 issuance will depend on future market conditions and capital expenditure requirements. Variances in interest expense related to the timing and amount of the issuances of the debt or the rates at which they are issued will be captured in the Flow-through deferral account.

8.3.2 Short-Term Debt

FBC obtains short-term funding primarily through the issuance of commercial paper to Canadian institutional investors. FBC backstops the commercial paper issuances by maintaining a $150 million committed credit facility that matures in April 2026.[55] This facility is also used to issue letters of credit. The credit facility, along with a $10 million overdraft facility, provides FBC with short-term liquidity to fund its capital program and working capital requirements.

8.3.3 Forecast of Interest Rates

FBC uses interest rate forecasts to estimate future interest expense. Forecasts of Treasury Bills and benchmark Government of Canada Bond interest rates are used in determining the overall interest rates for short-term debt and for rates on new issues of long-term debt, respectively. The forecasts are based on available projections made by Canadian Chartered banks.

Credit spreads on new long-term debt are based on current indicative rates, on the assumption that the current credit ratings of FBC are maintained.

FBC's short-term borrowing rate is based on the rate at which it issues commercial paper. Since commercial paper issuance rates are not forecast by economists, a forecast needs to be derived by FBC. The forecast is based on the historical differential between the Canadian Deposit Overnight Rate (CDOR) and the rate obtained by FBC under its commercial paper program. CDOR is used because FBC's short-term borrowings under its credit facility are priced based on CDOR and therefore CDOR is tracked relative to FBC's commercial paper borrowings. As CDOR is not forecast by economists, FBC must first obtain the 3-Month T-Bill rate forecast and then convert it to a CDOR forecast. FBC does this by taking the 3-year historical spread between CDOR and the 3-month T-Bill rate. Then, to derive the short-term borrowing rate forecast, FBC adjusts the CDOR forecast with the historical spread between CDOR and rates of issuances under its commercial paper program.

The 3-Month T-Bill forecast for 2023 is 3.14 percent, which is a significant increase from the 0.47 percent approved in 2022. FBC is in a rising interest rate environment due to high inflation, Russia's invasion in Ukraine, and the removal of monetary policy actions that were prevalent during the initial years of the COVID-19 pandemic (i.e., 2020 and 2021). In addition, on July 13, 2022 the Bank of Canada completed its fourth rate hike of the year, raising the benchmark interest

[54] Section 11, Schedule 27, Line 10.
[55] On July 14, 2021, the credit facility was extended to April 27, 2026.

rate to 2.5 percent from 0.25 percent at the beginning of 2022 and signalling that more rate hikes will be announced in 2022. The market volatility is expected to persist given many ongoing elevated risk variables.

For 2023, FBC forecasts a similar level of other financing fees to the 2022 Approved amount. Other financing fees include the fees that FBC incurs for its letters of credit under the $150 million credit facility, as well as interest paid on customer deposits. The short-term borrowing rate forecast is shown in Table 8-1 below.

Table 8-1: Short Term Interest Rate Forecast

FBC Short Term Interest Rate	Approved 2022	Projected 2022	Forecasted 2023
3-Month T-Bill Rate [1]	0.47%	3.08%	3.14%
Spread to CDOR	0.39%	0.36%	0.36%
CDOR Rate	0.86%	3.44%	3.50%
Spread to CP	-0.32%	-0.36%	-0.36%
CP Dealer Commission	0.10%	0.10%	0.10%
ST Interest Rate on Credit Facilities	**0.64%**	**3.18%**	**3.24%**
Fixed Financing Fees [2]			
Standby fee on Undrawn Credit [3]	0.44%	0.39%	0.44%
Renewal Fee on Undrawn Credit	0.17%	0.11%	0.12%
Other Financing Fees	0.26%	0.35%	0.44%
ST Interest Rate on Fixed Financing Fee	**0.87%**	**0.84%**	**1.00%**
FBC Short Term Rate	**1.51%**	**4.02%**	**4.24%**

Notes to Table:

[1] 3-Month T-Bill Rate for 2023 is a weighted average rate based on forecasts provided by Canadian Chartered banks in July 2022.

[2] Fixed financing fees represent the costs of maintaining the $150 million credit facility and letter of credit facility, which are fixed fees incurred regardless of whether FBC draws from the credit facility. The fees have been converted into a short-term rate for forecast purposes.

[3] A standby fee of 20 bps is charged on undrawn credit facility amounts, which would change if credit facility amounts are drawn through banker acceptances or prime loans. However, the forecast assumes FBC will borrow through commercial paper and will not change the undrawn credit facility fee percentage.

4. Other financing fees include commercial paper issuance fees, letter of credit fees, customer deposit interest expense and miscellaneous bank administration costs. The letter of credit fees, customer deposit interest and miscellaneous bank administration costs are incurred regardless of whether FBC draws from the credit facility.

As noted above, FBC's interest rate forecasts are based on CDOR. An indirect result of the cessation of the publication of the London Interbank Offered Rate (LIBOR) is that Canada is reassessing its use of CDOR as a risk-free rate benchmark for financial instruments in multiple asset classes. This will impact FBC's credit facility agreement as Refinitiv Benchmark Services (UK) Limited (RBSL), CDOR's regulated administrator, announced that CDOR will cease to be published after June 28, 2024.[56] The Canadian Alternative Reference Rate Working Group

[56] https://www.bankofcanada.ca/markets/canadian-alternative-reference-rate-working-group/.

(CARR) was established to coordinate the transition to a new risk-free rate benchmark. It is anticipated that CDOR will transition to the Canadian Overnight Repo Rate Average (CORRA), a transaction-based overnight risk-free interest rate benchmark in existence since 1997.[57] FBC will work with its banking syndicate members to transition its credit facility agreement to CORRA and will revisit the methodology for short-term interest rate forecasting when such a transition is complete.

8.3.4 Interest Expense Forecast

The interest expense forecast reflects FBC's existing and forecast borrowing costs on long- and short-term debt.

Short-term interest expense is determined by applying the forecast short-term debt rate to the estimated short-term debt balance. Long-term debt interest expense is determined using the straight-line method by multiplying the average balance of the specific debenture by the debt coupon rate, or forecast coupon rate, if it is a new issue. The 2023 long-term debt schedule for FBC can be found in Section 11, Schedule 27.

8.3.5 Allowance for Funds Used During Construction (AFUDC)

FBC applies AFUDC to projects that are greater than three months in duration and greater than $100 thousand. Based on the above information, FBC's AFUDC rate for 2023 (which is equal to its after-tax weighted average cost of capital) is 5.73 percent. The calculation of the rate is shown in the following table.

Table 8-2: Calculation of AFUDC Rate for 2023

	Weight	Pre Tax Rate	After Tax Rate	Earned Return
Short Term Debt	5.44%	4.24%	3.10%	4.24%
Long Term Debt	54.56%	4.78%	3.49%	4.78%
Common Equity	40.00%	12.53%	9.15%	9.15%
Weighted Average	100.00%	7.85%	5.73%	6.50%

8.4 *SUMMARY*

FBC's equity financing and ROE have been forecast for 2023 at the same percentages as approved for 2022. FBC's debt financing costs on rate base are primarily determined by embedded rates on long-term debt, and to a lesser degree by short-term debt rates; the embedded rate on long-term debt is forecast to decrease in 2023 as compared to 2022 Approved.

[57] https://www.bankofcanada.ca/wp-content/uploads/2021/12/CARR-Review-CDOR-Analysis-Recommendations.pdf.

9. TAXES

9.1 INTRODUCTION AND OVERVIEW

This section discusses FBC's forecasts of property taxes and income tax which have been forecast on a basis consistent with prior years. In 2023, property taxes are forecast to increase by 2.1 percent from 2022 Approved, while income tax is forecast to decrease by 19.9 percent compared to 2022 Approved.

9.2 PROPERTY TAXES

Property taxes for 2023 of $18.260 million incorporate Company forecasts of assessed values of taxable assets, mill rates and taxes from revenues earned from electricity consumed within municipalities. A breakdown of property taxes by asset type is provided in Table 9-1 below.

Table 9-1: Property Taxes ($ millions)

Line No.	Description	Approved 2022	Projected 2022	Forecast 2023
1	Generating Plant	$ 3.210	$ 3.199	$ 3.253
2	Transmission and Distribution	7.428	6.950	7.189
3	Substation Equipment	3.948	4.156	4.208
4	Land and Buildings	1.165	1.201	1.322
5	In-Lieu	2.138	2.115	2.288
6	Total Property Taxes	$ 17.889	$ 17.621	$ 18.260
7				
8	Forecast Change from 2022 Approved			2.1%
9	Forecast Change from 2022 Projected			3.6%

As shown in the above table, in 2023 property taxes are forecast to increase by 2.1 percent from 2022 Approved and increase by 3.6 percent compared to 2022 Projected. In general, the 2023 increase from 2022 Projected is due to construction activities, market value changes, and changes in tax policies of local taxing authorities. The most significant drivers of the forecast changes are as follows:

1. **Changes in Tax Rates.** Tax Rates are expected to change for 2023 as follows:
   a) Municipal rates are expected to increase by 1.0 percent;
   b) School rates are expected to decrease by 1.0 percent;
   c) Rural rates are expected to decrease by 0.4 percent;

d) Tax rates on First Nations are expected to increase by 0.8 percent; and

e) Other rates are expected to decrease by 1.4 percent.

2. **Changes in Revenues to Calculate Grants In Lieu of Taxes.** Revenues reported to municipalities are expected to increase by 8.2 percent based on actual revenues applicable to the taxation year. Grants in-lieu of taxes are based on a fixed percentage of revenues; the overall actual increase in revenues reported to municipalities increases the grants in-lieu of taxes due.

3. **Changes in Assessed Values.** Forecast changes in the assessed values of FBC's property are based on expected inflationary increases. These include:

a) A 5.2 percent increase in assessed values of distribution lines and a 2.5 percent increase in transmission lines;

b) A 2.5 percent increase in assessed values for generating facilities calculated using legislated cost manuals for valuing generating facilities;

c) A 0.5 percent decrease in assessed values for substations calculated using legislated cost manuals for valuing substations; and

d) Land values are expected to increase between 4.3 percent to 11.4 percent for right of ways and properties owned in fee simple.

Any variances from the forecast of property taxes included in rates are recorded in the Flow-through deferral account and will be returned to or recovered from customers in the following year.

9.3 *INCOME TAX*

FBC is subject to corporate income taxes imposed by the Federal and BC governments. Current income taxes have been calculated using the flow-through (taxes payable) method, consistent with BCUC-approved past practice, at the corporate tax rate of 27 percent for 2023, which is unchanged from 2022. The corporate tax rates used in this Application are based on the Canada Income Tax Act and the BC Income Tax Act enacted legislation and are updated each year as part of the annual rate setting process.

Income tax for 2023 is forecast to decrease by $1.494 million or 19.9 percent compared to 2022 Approved. The 2023 Forecast decrease is primarily due to higher deductible temporary differences associated with amortization of deferred charges and property, plant and equipment, and lower taxable temporary differences associated with pension and OPEB, partially offset by higher rate base.

Any tax rate variances and variances in income taxes on items that are flowed through in rates are subject to flow-through treatment.

All other differences in income tax expense are subject to earnings sharing.

9.4 *SUMMARY*

FBC has forecast its property and income taxes on a basis consistent with prior years, utilizing enacted legislation for income taxes and forecast changes for property tax rates and assessments.

10. EARNINGS SHARING

In the MRP Decision (at page 82), the BCUC approved an earnings sharing mechanism from 2020 to 2024 whereby 50 percent of the achieved ROE above or below the allowed ROE will be shared with customers. Since FBC is unable to determine final earnings sharing until all items required for the ROE calculation are known, including the final rate base, there is a lag in when FBC distributes earnings sharing amounts. This is consistent with the calculations of formula O&M, where the true-up of the formula inputs happens only once actuals are known. Thus, for 2023 rates, it is the 2021 formula O&M and 2021 earnings sharing amounts that are calculated and impact rates in 2023.

For 2023, FBC proposes to distribute a $0.911 million pre-tax credit ($0.665 million after-tax) to customers, comprised of:

- The $0.665 million credit difference between the projected 2021 deferral account after-tax credit addition of zero embedded in 2022 rates, and the actual 2021 deferral account after-tax credit addition of $0.665 million as provided in FBC's 2021 Annual Report to the BCUC. This amount is also shown in the opening 2023 balance[58] in the financial schedules in the Application.

FBC proposes to distribute $0.911 million to customers in 2023 as a reduction in 2023 revenue requirements through amortization of the projected 2023 opening after-tax balance of $0.665 million in the MRP Earnings Sharing deferral account.

As part of future rate filings, the actual earnings sharing for 2022 will be distributed to or collected from customers in a similar manner as described above, which will account for the actual 2022 ROE variance from approved.

[58] Section 11, Schedule 12.2, Line 14, Column 2.

11. FINANCIAL SCHEDULES

Description	Schedule Reference
Summary Of Rate Change	1
Rate Base	
Utility Rate Base	2
Formula Inflation Factors	3
Capital Expenditures	4
Capital Expenditures To Plant Reconciliation	5
Plant In Service Continuity Schedule	6
Accumulated Depreciation Continuity Schedule	7
Schedule Not Applicable	8
Contributions In Aid Of Construction Continuity Schedule	9
Schedule Not Applicable	10
Unamortized Deferred Charges And Amortization - Rate Base	11
Unamortized Deferred Charges And Amortization - Non-Rate Base	12
Working Capital Allowance	13
Cash Working Capital	14
Schedule Not Applicable	15
Revenue Requirement	
Utility Income And Earned Return	16
Volume And Revenue	17
Revenue At Existing And Revised Rates	18
Cost Of Energy	19
Operating And Maintenance Expense	20
Depreciation And Amortization Expense	21
Property And Sundry Taxes	22
Other Revenue	23
Income Taxes	24
Capital Cost Allowance	25
Return On Capital	26
Embedded Cost Of Long Term Debt	27

SUMMARY OF RATE CHANGE
FOR THE YEAR ENDING DECEMBER 31, 2023
($millions)

Line No.	Particulars	2023 Forecast		Cross Reference
	(1)	(2)	(3)	(4)
1	**VOLUME/REVENUE RELATED**			
2	Customer Growth and Volume	$ (12.546)		
3	Change in Other Revenue	(0.409)	(12.955)	
4				
5	**POWER SUPPLY**			
6	Power Purchases	19.796		
7	Wheeling	0.894		
8	Water Fees	(0.415)	20.275	
9				
10	**O&M CHANGES**			
11	Gross O&M Change	4.757		
12	Capitalized Overhead Change	(0.741)	4.016	
13				
14	**DEPRECIATION EXPENSE**			
15	Depreciation from Net Additions		2.752	
16				
17	**AMORTIZATION EXPENSE**			
18	CIAC from Net Additions	(0.210)		
19	Deferrals	(4.835)	(5.045)	
20				
21	**FINANCING AND RETURN ON EQUITY**			
22	Financing Rate Changes	3.688		
23	Financing Ratio Changes	(1.049)		
24	Rate Base Growth	5.809	8.448	
25				
26	**TAX EXPENSE**			
27	Property and Other Taxes	0.371		
28	Other Income Taxes Changes	(1.494)	(1.123)	
29				
30	**REVENUE DEFICIENCY (SURPLUS)**		**$ 16.368**	Schedule 16, Line 6, Column 4
31				
32	Revenue at Existing Rates		409.840	Schedule 18, Line 7, Column 3
33	Rate Change		3.99%	

UTILITY RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Schedule 2

Line No.	Particulars	2022 Approved	2023 at Revised Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	Plant in Service, Beginning	$ 2,279,658	$ 2,375,297	$ 95,639	Schedule 6.1, Line 32, Column 3
2	Opening Balance Adjustment	4,512	-	(4,512)	Schedule 6.1, Line 32, Column 4
3	Net Additions	105,010	134,666	29,656	Schedule 6.1, Line 32, Column 5+6+7
4	Plant in Service, Ending	2,389,180	2,509,963	120,783	
5					
6	Accumulated Depreciation Beginning	$ (659,517)	$ (693,759)	$ (34,242)	Schedule 7.1, Line 32, Column 5
7	Opening Balance Adjustment	(569)	-	569	Schedule 7.1, Line 32, Column 6
8	Net Additions	(33,657)	(47,865)	(14,208)	Schedule 7.1, Line 32, Column 7+8+9
9	Accumulated Depreciation Ending	(693,743)	(741,624)	(47,881)	
10					
11	CIAC, Beginning	$ (232,291)	$ (243,101)	$ (10,810)	Schedule 9, Line 3, Column 2
12	Opening Balance Adjustment	(2,523)	-	2,523	
13	Net Additions	(11,712)	(11,628)	84	Schedule 9, Line 3, Column 5+6
14	CIAC, Ending	(246,526)	(254,729)	(8,203)	
15					
16	Accumulated Amortization Beginning - CIAC	$ 84,284	$ 89,140	$ 4,856	Schedule 9, Line 7, Column 2
17	Opening Balance Adjustment	212	-	(212)	
18	Net Additions	4,857	5,067	210	Schedule 9, Line 7, Column 5+6
19	Accumulated Amortization Ending - CIAC	89,353	94,207	4,854	
20					
21	Net Plant in Service, Mid-Year	$ 1,506,015	$ 1,567,697	$ 61,682	
22					
23	Adjustment for timing of Capital additions	$ 16,181	$ 22,720	$ 6,539	
24	Capital Work in Progress, No AFUDC	19,332	34,306	14,974	
25	Unamortized Deferred Charges	30,372	40,045	9,673	Schedule 11, Line 26, Column 8
26	Working Capital	6,258	6,100	(158)	Schedule 13, Line 9, Column 3
27	Utility Plant Acquisition Adjustment	4,749	4,563	(186)	
28					
29	Mid-Year Utility Rate Base	$ 1,582,907	$ 1,675,431	$ 92,524	

FORTISBC INC. FBC Annual Review for 2023 Rates - August 5, 2022 Section 11

Schedule 3

FORMULA INFLATION FACTORS
FOR THE YEARS ENDING DECEMBER 31, 2020 to 2023
($000s)

Line No.	Particulars	Reference	2020	2021	2022	2023	Total for 2023 Rate Setting	Cross Ref
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**Formula Cost Drivers**							
2	CPI		2.692%	1.596%	1.281%	4.940%		
3	AWE		2.881%	5.745%	6.455%	4.235%		
4	Labour Split							
5	Non Labour		38.000%	38.000%	37.000%	40.000%		
6	Labour		62.000%	62.000%	63.000%	60.000%		
7	CPI/AWE	(Line 2 x Line 5) + (Line 3 x Line 6)	2.809%	4.168%	4.541%	4.517%		
8	Productivity Factor	G-166-20	-0.500%	-0.500%	-0.500%	-0.500%		
9	Net Inflation Factor	Line 7 + Line 8	2.309%	3.668%	4.041%	4.017%		
10								
11								
12	**Growth in Average Customer Calculation**							
13	Actual/Projected Prior Year Average Customers		139,916	142,321	144,877	147,417		
14	Average Customers for the Year	Schedule 18, Line 7, Column 6	142,321	144,877	147,417	150,563		
15	Change in Average Customers	Line 14 - Line 13	2,405	2,556	2,541	3,145	10,647	
16								
17	Customer Growth Factor Multiplier	G-166-20					75%	
18	Change in Average Customers for Rate Setting Purposes	Line 15 x Line 17					7,985	
19								
20	Average Customers Used to Determine Starting UCOM	Line 13 Year 2020					139,916	
21								
22	Average Customer Forecast - 2023 Rate Setting Purposes	Line 18 + Line 20					147,901	

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Schedule 4

CAPITAL EXPENDITURES
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Particulars	Total CapEx	Cross Reference
	(1)	(2)	(3)
1	**Forecast Capital Expenditures**		
2	Growth Capital	$ 30,973	
3	Sustainment Capital	45,797	
4	Other Capital	17,658	
5	Total Forecast Capital	$ 94,428	
6			
7	**Flow-Through Capital Expenditures**		
8	MRS Capital	$ -	
9	EV Charging Stations	248	
10	Total Flow-Through Capital	$ 248	
11			
12	**Total Regular Capital Expenditures**	$ 94,676	

FORTISBC INC. FBC Annual Review for 2023 Rates - August 5, 2022 Section 11

Schedule 5

CAPITAL EXPENDITURES TO PLANT RECONCILIATION
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Particulars	2023 Formula		Cross Reference
	(1)	(2)		(3)
1	**CAPEX**			
2	Forecast Capital Expenditures	$	94,428	
3	Flow-Through Capital		248	
4	Total Regular Capital Expenditures	$	94,676	Schedule 4, Column 2, Line 12
5				
6	**Special Projects and CPCN's**			
7	Kelowna Bulk Transformer Capacity Addition	$	1,710	
8	Total Special Projects and CPCN's	$	1,710	
9				
10	**Total Capital Expenditures**	$	96,386	
11				
12				
13	**RECONCILIATION OF CAPITAL EXPENDITURES TO PLANT**			
14				
15	Regular Capital Expenditures	$	94,676	Line 4
16	Add - Capitalized Overheads		10,918	Schedule 20, Column 4, Line 23
17	Add - AFUDC		243	
18	Gross Capital Expenditures		105,837	
19	Change in Work in Progress		-	
20	**Total Regular Additions to Plant**	$	105,837	
21				
22	Special Projects and CPCN's Capital Expenditures	$	1,710	Line 8
23	Add - AFUDC		49	
24	Gross Capital Expenditures		1,759	
25	Change in Work in Progress		43,680	
26	**Total Special Projects and CPCN Additions to Plant**	$	45,439	
27				
28	**Grand Total Additions to Plant**	$	151,276	Schedule 6.1, Columns 5 + 6, Line 32

FORTISBC INC. FBC Annual Review for 2023 Rates - August 5, 2022 Section 11

PLANT IN SERVICE CONTINUITY SCHEDULE Schedule 6
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Account	Particulars	12/31/2022	Opening Bal Adjustment	CPCN's	Additions	Retirements	12/31/2023	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1		**Hydraulic Production Plant**							
2	330	Land Rights	$ 962	$ -	$ -	$ -	$ -	$ 962	
3	331	Structures and Improvements	22,045	-	-	167	(12)	22,200	
4	332	Reservoirs, Dams & Waterways	119,076	-	16,151	7,747	(782)	142,192	
5	333	Water Wheels, Turbines and Gen.	105,453	-	2	699	(142)	106,012	
6	334	Accessory Equipment	51,357	-	-	128	(38)	51,447	
7	335	Other Power Plant Equipment	48,572	-	-	5	(1)	48,576	
8	336	Roads, Railroads and Bridges	1,287	-	-	-	-	1,287	
9			$ 348,752	$ -	$ 16,153	$ 8,746	$ (975)	$ 372,676	
10									
11		**Transmission Plant**							
12	350	Land Rights-R/W	$ 10,767	$ -	$ -	$ 118	$ -	$ 10,885	
13	350.1	Land Rights-Clearing	9,992	-	-	118	-	10,110	
14	353	Station Equipment	243,150	-	21,250	3,446	(305)	267,541	
15	355	Poles Towers & Fixtures	127,975	-	-	6,450	(291)	134,134	
16	356	Conductors and Devices	123,228	-	-	6,449	(313)	129,364	
17	359	Roads and Trails	959	-	-	-	-	959	
18			$ 516,071	$ -	$ 21,250	$ 16,581	$ (909)	$ 552,993	

FORTISBC INC.

PLANT IN SERVICE CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Schedule 6.1

Line No.	Account	Particulars	12/31/2022	Opening Bal Adjustment	CPCN's	Additions	Retirements	12/31/2023	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1		**Distribution Plant**							
2	360	Land Rights-R/W	$ 7,185	$ -	$ -	$ 817	$ -	$ 8,002	
3	360.1	Land Rights-Clearing	11,630	-	-	374	-	12,004	
4	362	Station Equipment	304,310	-	8,036	13,065	(885)	324,526	
5	364	Poles Towers & Fixtures	258,898	-	-	13,410	(570)	271,738	
6	365	Conductors and Devices	436,812	-	-	20,531	(728)	456,615	
7	368	Line Transformers	193,494	-	-	14,165	(1,815)	205,844	
8	369	Services	9,521	-	-	-	-	9,521	
9	370.1	AMI Meters	41,459	-	-	532	-	41,991	
10	371	Installation on Customers' Premises	938	-	-	-	-	938	
11	373	Street Lighting and Signal System	14,178	-	-	170	(42)	14,306	
12	372	EV Stations Kiosks & Charger Connectors	5,993	-	-	-	-	5,993	
13			$ 1,284,418	$ -	$ 8,036	$ 63,064	$ (4,040)	$ 1,351,478	
14									
15		**General Plant**							
16	389	Land	$ 11,184	$ -	$ -	$ -	$ -	$ 11,184	
17	390.1	Structures - Masonry	48,652	-	-	2,785	(319)	51,118	
18	390.2	Operation Building	19,432	-	-	609	(23)	20,018	
19	390.1	Leasehold Improvements	2,872	-	-	-	-	2,872	
20	391	Office Furniture & Equipment	5,399	-	-	215	(237)	5,377	
21	391.1	Computer Hardware	13,614	-	-	3,330	(3,016)	13,928	
22	391.2	Computer Software	41,906	-	-	7,033	(4,015)	44,924	
23	391.2	AMI Software	13,439	-	-	(3)	-	13,436	
24	392.1	Light Duty Vehicles	5,967	-	-	549	(484)	6,032	
25	392.1	Heavy Duty Vehciles	28,678	-	-	1,523	(351)	29,850	
26	394	Tools and Work Equipment	8,507	-	-	724	(587)	8,644	
27	397	Communication Structures & Equipment	15,707	-	-	681	(1,456)	14,932	
28	397.1	Fibre	5,729	-	-	-	(198)	5,531	
29	397.2	AMI Communications Structure & Equipment	4,970	-	-	-	-	4,970	
30			$ 226,056	$ -	$ -	$ 17,446	$ (10,686)	$ 232,816	
31									
32		**Total Plant in Service**	$ 2,375,297	$ -	$ 45,439	$ 105,837	$ (16,610)	$ 2,509,963	
33									
34		Cross Reference			Schedule 5, Line 26, Column 2	Schedule 5, Line 20, Column 2			

FORTISBC INC.

ACCUMULATED DEPRECIATION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Schedule 7

Line No.	Account	Particulars	Gross Plant for Depreciation	Depreciation Rate	12/31/2022	Opening Bal Adjustment	Depreciation Expense	Retirements	Cost of Removal	Adjustments	12/31/2023	Cross Ref
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
1		**Hydraulic Production Plant**										
2	330	Land Rights	$ 962	1.07%	$ (382)	$ -	$ 10	$ -	$ -	$ -	$ (372)	
3	331	Structures and Improvements	22,045	1.68%	5,718	-	370	(12)	-	-	6,076	
4	332	Reservoirs, Dams & Waterways	135,227	1.90%	7,278	-	2,569	(782)	(1,857)	-	7,208	
5	333	Water Wheels, Turbines and Gen.	105,455	1.79%	20,564	-	1,888	(142)	(3)	-	22,307	
6	334	Accessory Equipment	51,357	3.13%	15,121	-	1,607	(38)	(130)	-	16,560	
7	335	Other Power Plant Equipment	48,572	2.12%	20,171	-	1,030	(1)	-	-	21,200	
8	336	Roads, Railroads and Bridges	1,287	1.44%	476	-	19	-	-	-	495	
9			$ 364,905		$ 68,946	$ -	$ 7,493	$ (975)	$ (1,990)	$ -	$ 73,474	
10												
11		**Transmission Plant**										
12	350	Land Rights-R/W	$ 10,767	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
13	350.1	Land Rights-Clearing	9,992	1.27%	2,485	-	127	-	-	-	2,612	
14	353	Station Equipment	264,400	2.33%	101,920	-	6,161	(305)	(159)	-	107,617	
15	355	Poles Towers & Fixtures	127,975	2.52%	39,342	-	3,225	(291)	(469)	-	41,807	
16	356	Conductors and Devices	123,228	2.52%	24,036	-	3,105	(313)	(469)	-	26,359	
17	359	Roads and Trails	959	1.96%	432	-	19	-	-	-	451	
18			$ 537,321		$ 168,215	$ -	$ 12,637	$ (909)	$ (1,097)	$ -	$ 178,846	

FORTISBC INC.

ACCUMULATED DEPRECIATION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Schedule 7.1

Line No.	Account	Particulars	Gross Plant for Depreciation	Depreciation Rate	12/31/2022	Opening Bal Adjustment	Depreciation Expense	Retirements	Cost of Removal	Adjustments	12/31/2023	Cross Ref
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
1		**Distribution Plant**										
2	360	Land Rights-R/W	$ 7,185	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
3	360.1	Land Rights-Clearing	11,630	1.25%	2,935	-	145	-	-	-	3,080	
4	362	Station Equipment	312,346	2.61%	93,321	-	8,152	(885)	(156)	-	100,432	
5	364	Poles Towers & Fixtures	258,898	2.73%	80,092	-	7,068	(570)	(567)	-	86,023	
6	365	Conductors and Devices	436,812	2.38%	129,625	-	10,396	(728)	(914)	-	138,379	
7	368	Line Transformers	193,494	3.13%	45,961	-	6,056	(1,815)	(347)	-	49,855	
8	369	Services	9,521	0.51%	6,807	-	49	-	-	-	6,856	
9	370.1	AMI Meters	41,459	6.25%	12,897	-	2,591	-	-	-	15,488	
10	371	Installation on Customers' Premises	938	0.00%	937	-	-	-	-	-	937	
11	373	Street Lighting and Signal System	14,178	4.95%	6,259	-	702	(42)	-	-	6,919	
12	372	EV Stations Kiosks & Charger Connectors	5,993	10.00%	914	-	599	-	-	-	1,513	
13			$ 1,292,454		$ 379,748	$ -	$ 35,758	$ (4,040)	$ (1,984)	$ -	$ 409,482	
14												
15		**General Plant**										
16	389	Land	$ 11,184	0.00%	$ 34	$ -	$ -	$ -	$ -	$ -	$ 34	
17	390.1	Structures - Masonry	48,652	2.53%	13,006	-	1,231	(319)	-	-	13,918	
18	390.2	Operation Building	19,432	1.63%	7,081	-	317	(23)	-	-	7,375	
19	390.1	Leasehold Improvements	2,872	1.63%	2,700	-	47	-	-	-	2,747	
20	391	Office Furniture & Equipment	5,399	4.42%	1,501	-	239	(237)	-	-	1,503	
21	391.1	Computer Hardware	13,614	21.60%	4,496	-	2,941	(3,016)	-	-	4,421	
22	391.2	Computer Software	41,906	8.96%	16,368	-	3,755	(4,015)	-	-	16,108	
23	391.2	AMI Software	13,439	10.00%	7,627	-	1,344	-	-	-	8,971	
24	392.1	Light Duty Vehicles	5,967	3.81%	2,528	-	227	(484)	77	-	2,348	
25	392.1	Heavy Duty Vehciles	28,678	6.50%	8,066	-	1,864	(351)	-	-	9,579	
26	394	Tools and Work Equipment	8,507	4.11%	3,500	-	350	(587)	-	-	3,263	
27	397	Communication Structures & Equipment	15,707	3.44%	5,067	-	540	(1,456)	(5)	-	4,146	
28	397.1	Fibre	5,729	6.97%	2,486	-	399	(198)	-	-	2,687	
29	397.2	AMI Communications Structure & Equipment	4,970	6.67%	2,390	-	332	-	-	-	2,722	
30			$ 226,056		$ 76,850	$ -	$ 13,586	$ (10,686)	$ 72	$ -	$ 79,822	
31												
32		**Total**	$ 2,420,736		$ 693,759	$ -	$ 69,474	$ (16,610)	$ (4,999)	$ -	$ 741,624	
33												
34		Cross Reference	Schedule 6.1, Line 32, Column 3+4+5									

SCHEDULE NOT APPLICABLE

FORTISBC INC. FBC Annual Review for 2023 Rates - August 5, 2022 Section 11

Schedule 9

CONTRIBUTIONS IN AID OF CONSTRUCTION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Particulars	12/31/2022	CPCN / Open Bal Adjt	Adjustment	Additions	Retirements	12/31/2023	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**CIAC**							
2	CIAC	$ 243,101	$ -	$ -	$ 11,628	$ -	$ 254,729	
3	**Total**	$ 243,101	$ -	$ -	$ 11,628	$ -	$ 254,729	
4								
5	**Amortization**							
6	Amortization	$ (89,140)	$ -	$ -	$ (5,067)	$ -	$ (94,207)	
7	**Total**	$ (89,140)	$ -	$ -	$ (5,067)	$ -	$ (94,207)	
8								
9	**Net CIAC**	$ 153,961	$ -	$ -	$ 6,561	$ -	$ 160,522	

SCHEDULE NOT APPLICABLE

FORTISBC INC. FBC Annual Review for 2023 Rates - August 5, 2022 Section 11

Schedule 11

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Particulars	12/31/2022	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	12/31/2023	Mid-Year Average	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**1. Forecasting Variance Accounts**								
2	BCUC Levies Variance Account	$ 32	$ -	$ -	$ -	$ (32)	$ -	$ 16	
3									
4	**2. Rate Smoothing Accounts**								
5									
6	**3. Benefits Matching Accounts**								
7	Preliminary and Investigative Charges	$ 2,646	$ -	$ (439)	$ -	$ -	$ 2,207	$ 2,427	Note 1
8	Demand Side Management	37,219	-	14,455	(3,903)	(5,829)	41,942	39,581	
9	Deferred Debt Issue Costs	4,074	-	600	(111)	(167)	4,396	4,235	
10	Joint Pole Use Audit 2023	-	-	435	(117)	(64)	254	127	
11	2021 Generic Cost of Capital Proceeding	675	-	450	(122)	-	1,003	839	
12	Annual Reviews for 2020-2024 Rates	154	-	200	(54)	(154)	146	150	
13	2021 Long Term Electric Resource Plan	264	-	250	(68)	(113)	333	298	
14	BCUC Initiated Inquiry Costs	109	-	100	(27)	(109)	73	91	
15	Mandatory Reliability Standards 2021 Audit	157	-	-	-	(79)	78	118	
16		$ 45,298	$ -	$ 16,051	$ (4,402)	$ (6,515)	$ 50,432	$ 47,866	
17									
18	**4. Retroactive Expense Accounts**								
19									
20	**5.Other Accounts**								
21	Pension and OPEB Liability	$ (10,592)	$ -	$ 4,664	$ -	$ -	$ (5,928)	$ (8,260)	
22	COVID-19 Customer Recovery Fund	507	-	-	-	(169)	338	423	
23	Indigenous Relations Agreement (Huth Substation)	-	-	-	-	-	-	-	
24		$ (10,085)	$ -	$ 4,664	$ -	$ (169)	$ (5,590)	$ (7,837)	
25									
26	**Total Rate Base Deferral Accounts**	$ 35,245	$ -	$ 20,715	$ (4,402)	$ (6,716)	$ 44,842	$ 40,045	
27									

28 Note 1: Gross Additions for Preliminary and Investigative Charges are after transfers to Construction Work in Progress. Additions of $0.851 million - transfer of $1.290 million = $(0.439) million.

FORTISBC INC. FBC Annual Review for 2023 Rates - August 5, 2022 Section 11

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - NON-RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Schedule 12

Line No.	Particulars	12/31/2022	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	12/31/2023	Mid-Year Average	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**Deferral Accounts Financed at Short Term Interest Rate**								
2									
3	**1. Forecasting Variance Accounts**								
4	Pension & Other Post Retirement Benefits (OPEB) Variance	$ 1,493	$ -	$ -	$ -	$ (604)	$ 889	$ 1,191	
5									
6	**2. Rate Smoothing Accounts**								
7									
8	**3. Benefits Matching Accounts**								
9	Tariff Applications	31	-	-	-	(31)	-	15	
10		$ 31	$ -	$ -	$ -	$ (31)	$ -	$ 15	
11									
12	**4. Retroactive Expense Accounts**								
13									
14	**5.Other Accounts**								
15									
16	**Total NRB Deferral Accounts at Short Term Interest**	$ 1,524	$ -	$ -	$ -	$ (635)	$ 889	$ 1,206	
17									
18	Financing Costs at STI	$ 8	$ -	$ 37	$ -	$ (8)	$ 37	$ 23	

FORTISBC INC.

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - NON-RATE BASE cont'd
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Schedule 12.1

Line No.	Particulars	12/31/2022	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	12/31/2023	Mid-Year Average	Cross Ref
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**Deferral Accounts Financed at Weighted Average Cost of Debt**								
2									
3	**1. Forecasting Variance Accounts**								
4									
5	**2. Rate Smoothing Accounts**								
6									
7	**3. Benefits Matching Accounts**								
8	CPCN Projects Preliminary Engineering [1]	$ 980	$ -	$ 450	$ -	$ -	$ 1,430	$ 1,205	
9	2017 Rate Design Application	236	-	-	-	(118)	118	177	
10	2020 - 2024 Multi-Year Rate Plan Application	290	-	-	-	(145)	145	217	
11	Rate Design and Rates for Electric Vehicle Direct Current Fast Charging Service Application	127	-	-	-	(59)	68	98	
12		$ 1,633	$ -	$ 450	$ -	$ (322)	$ 1,761	$ 1,697	
13									
14	**4. Retroactive Expense Accounts**								
15									
16	**5.Other Accounts**								
17	US GAAP Pension and OPEB Transition Obligation	$ 348	$ -	$ (348)	$ -	$ -	$ -	$ 174	
18	Advanced Metering Infrastructure Radio-Off Shortfall	25	-	-	-	(25)	-	12	
19		$ 373	$ -	$ (348)	$ -	$ (25)	$ -	$ 186	
20									
21	**Total NRB Deferral Accounts at Weighted Average Cost of Debt**	$ 2,006	$ -	$ 102	$ -	$ (347)	$ 1,761	$ 1,883	
22									
23	Financing Costs at WACD	$ 64	$ -	$ 66	$ -	$ (64)	$ 66	$ 65	

24 Note 1: Gross additions for CPCN Projects Preliminary Engineering after transfers to Construction Work in Progress.

FORTISBC INC.

Schedule 12.2

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - NON-RATE BASE cont'd
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Particulars	12/31/2022	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	12/31/2023	Mid-Year Average	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**Deferral Accounts Financed at Weighted Average Cost of Capital**								
2									
3	**1. Forecasting Variance Accounts**								
4	2020 - 2024 Flow-Through Deferral Account	$ (9,625)	$ -	$ -	$ -	$ 9,625	$ -	$ (4,813)	
5									
6	**2. Rate Smoothing Accounts**								
7									
8	**3. Benefits Matching Accounts**								
9	On Bill Financing (OBF) Participant Loans	$ 1	$ -	$ (1)	$ -	$ -	$ -	$ 1	
10									
11	**4. Retroactive Expense Accounts**								
12									
13	**5.Other Accounts**								
14	MRP Earnings Sharing Account	$ (665)	$ -	$ -	$ -	$ 665	$ -	$ (333)	
15									
16	**Total NRB Deferral Accounts at Weighted Average Cost of Capital**	$ (10,289)	$ -	$ (1)	$ -	$ 10,290	$ -	$ (5,145)	
17									
18	Financing Costs at AFUDC	$ (757)	$ -	$ (317)	$ -	$ 757	(317)	(537)	
19									
20	**Non Rate Base Deferral Accounts Non-Interest Bearing**	$ 50	$ -	$ -	$ -	$ -	$ 50	$ 50	
21									
22									
23	**Total Non Rate Base Deferral Accounts (including financing)**	**$ (7,394)**	**$ -**	**$ (113)**	**$ -**	**$ 9,993**	**$ 2,487**	**$ (2,455)**	

FORTISBC INC.

FBC Annual Review for 2023 Rates - August 5, 2022

Section 11

Schedule 13

WORKING CAPITAL ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Particulars	2022 Approved	2023 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Cash Working Capital**				
2	Cash Working Capital	$ 7,065	$ 6,850	$ (215)	Schedule 14, Line 32, Column 5
3					
4	Add/Less: Funds Unavailable/(Funds Available)				
5	Customers Loans	329	353	24	
6	Employee Loans	443	570	127	
7	Inventories - Materials and Supplies	612	649	37	
8	Employee Withholdings	(2,191)	(2,322)	(131)	
9	Total	$ 6,258	$ 6,100	$ (158)	

FORTISBC INC.

FBC Annual Review for 2023 Rates - August 5, 2022

Section 11

Schedule 14

CASH WORKING CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Particulars	2023 at Revised Rates	Lag (Lead) Days	Extended	Weighted Average Lag (Lead) Days	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)
1	**REVENUE**					
2	**Sales Revenue**					
3	Residential Tariff Revenue	$ 205,868	56.0	$ 11,528,608		
4	Commercial Tariff Revenue	110,473	45.1	4,982,332		
5	Wholesale Tariff Revenue	54,109	37.5	2,029,088		
6	Industrial Tariff Revenue	49,767	38.0	1,891,146		
7	Lighting Tariff Revenue	2,295	34.6	79,407		
8	Irrigation Tariff Revenue	3,696	47.0	173,712		
9						
10	**Other Revenue**					
11	Apparatus and Facilities Rental	$ 6,108	90.0	$ 549,720		
12	Contract Revenue	2,367	62.2	147,227		
13	Transmission Access Revenue	1,834	65.2	119,577		
14	Late Payment Charges	994	54.0	53,658		
15	Connection Charges	553	30.5	16,867		
16	Other Utility Income	385	63.4	24,409		
17	Total	$ 438,449		$ 21,595,751		49.3
18						
19	**EXPENSES**					
20	Power Purchases	$ 163,575	(51.5)	$ (8,424,126)		
21	Wheeling	6,987	(46.9)	(327,699)		
22	Water Fees	11,543	(1.4)	(16,160)		
23	Operating and Maintenance	61,871	(28.6)	(1,769,501)		
24	Property Taxes	18,260	(4.9)	(89,474)		
25	GST	593	(45.4)	(26,900)		
26	Income Tax	6,005	(15.2)	(91,276)		
27	Total	$ 268,833		$ (10,745,136)		(40.0)
28						
29	Net Lag (Lead) Days					9.3
30	Total Expenses				$	268,833
31						
32	Cash Working Capital				$	6,850

SCHEDULE NOT APPLICABLE

FORTISBC INC. FBC Annual Review for 2023 Rates - August 5, 2022 Section 11

Schedule 16

UTILITY INCOME AND EARNED RETURN
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Particulars	2022 Approved	2023 Forecast at 2022 Approved Rates	2023 Forecast Revised Revenue	2023 Forecast at Revised Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**ENERGY VOLUMES**						
2	Sales Volume (GWh)	3,306	3,476	-	3,476	170	Schedule 17, Line 8, Column 3
3							
4	**REVENUE**						
5	Sales	$ 397,294	$ 409,840	$ -	$ 409,840	$ 12,546	Schedule 17, Line 17, Column 3
6	Deficiency (Surplus)	-	-	16,368	16,368	16,368	
7	Total	397,294	409,840	16,368	426,208	28,914	Schedule 18, Line 7, Column 5
8							
9	**EXPENSES**						
10	Cost of Energy	$ 161,830	$ 182,105	$ -	$ 182,105	$ 20,275	Schedule 19, Line 30, Column 3
11	O&M Expense (net)	57,855	61,871	-	61,871	4,016	Schedule 20, Line 24, Column 4
12	Depreciation & Amortization	63,609	61,316	-	61,316	(2,293)	Schedule 21, Line 11, Column 3
13	Property Taxes	17,889	18,260	-	18,260	371	Schedule 22, Line 6, Column 3
14	Other Revenue	(11,832)	(12,241)	-	(12,241)	(409)	Schedule 23, Line 9, Column 3
15	Utility Income Before Income Taxes	107,943	98,529	16,368	114,897	6,954	
16							
17	Income Taxes	7,499	1,589	4,416	6,005	(1,494)	Schedule 24, Line 13, Column 3
18							
19	**EARNED RETURN**	$ 100,444	$ 96,940	$ 11,952	$ 108,892	$ 8,448	Schedule 26, Line 5, Column 7
20							
21	**UTILITY RATE BASE**	$ 1,582,907	$ 1,675,028		$ 1,675,431	$ 92,524	Schedule 2, Line 29, Column 3
22	**RATE OF RETURN ON UTILITY RATE BASE**	6.35%	5.79%		6.50%	0.15%	Schedule 26, Line 5, Column 6

FORTISBC INC. FBC Annual Review for 2023 Rates - August 5, 2022 Section 11

Schedule 17

VOLUME AND REVENUE
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Particulars	2022 Approved	2023 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**ENERGY VOLUME SOLD (GWh)**				
2	Residential	1,283	1,301	18	
3	Commercial	946	973	27	
4	Wholesale	560	578	18	
5	Industrial	470	575	105	
6	Lighting	10	9	(1)	
7	Irrigation	37	39	2	
8	Total	3,306	3,476	170	
9					
10	**REVENUE AT EXISTING RATES**				
11	Residential	$ 195,058	$ 197,962	$ 2,904	
12	Commercial	104,380	106,230	1,850	
13	Wholesale	51,255	52,031	776	
14	Industrial	40,804	47,856	7,052	
15	Lighting	2,411	2,207	(204)	
16	Irrigation	3,386	3,554	168	
17	Total	$ 397,294	$ 409,840	$ 12,546	

FORTISBC INC. FBC Annual Review for 2023 Rates - August 5, 2022 Section 11

Schedule 18

REVENUE AT EXISTING AND REVISED RATES
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Particulars	2022 Approved Revenue	2023 Forecast Revenue at 2022 Approved Rates	2023 Forecast Effective Increase	2023 Forecast Revenue at Revised Rates	Average Number of Customers	GWh	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	Residential	$ 195,058	$ 197,962	$ 7,906	$ 205,868	130,787	1,301	
2	Commercial	104,380	106,230	4,243	110,473	17,267	973	
3	Wholesale	51,255	52,031	2,078	54,109	6	578	
4	Industrial	40,804	47,856	1,911	49,767	42	575	
5	Lighting	2,411	2,207	88	2,295	1,358	9	
6	Irrigation	3,386	3,554	142	3,696	1,103	39	
7	Total	$ 397,294	$ 409,840	$ 16,368	$ 426,208	150,563	3,476	
8								
9	**Effective Increase**			3.99%				

FORTISBC INC. FBC Annual Review for 2023 Rates - August 5, 2022 Section 11

COST OF ENERGY Schedule 19
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Particulars	2022 Approved	2023 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**POWER PURCHASES**				
2	Gross Load (GWh)	3,591	3,775	184	
3					
4	**Power Purchase Expense**				
5	Brilliant	$ 41,841	$ 44,050	$ 2,209	
6	BC Hydro PPA	44,062	71,302	27,240	
7	Waneta Expansion	42,701	41,834	(867)	
8	Market and Contracted Producers	15,102	6,326	(8,776)	
9	Independent Power Producers	73	62	(11)	
10	Self-Generators	-	-	-	
11	CPA Balancing Pool	-	-	-	
12	Total	$ 143,779	$ 163,575	$ 19,796	
13					
14	**WHEELING**				
15	**Wheeling Nomination (MW months)**				
16	Okanagan Point of Interconnection	2,475	2,670	195	
17	Creston	420	420	-	
18					
19	**Wheeling Expense**				
20	Okanagan Point of Interconnect	$ 4,903	$ 5,555	$ 652	
21	Creston	542	570	28	
22	Other	648	863	215	
23	Total	$ 6,093	$ 6,987	$ 894	
24					
25	**WATER FEES**				
26	Plant Entitlement Use in previous year (GWh)	1,679	1,571	(108)	
27					
28	Water Fees	$ 11,958	$ 11,543	$ (415)	
29					
30	Total	$ 161,830	$ 182,105	$ 20,275	

FORTISBC INC. FBC Annual Review for 2023 Rates - August 5, 2022 Section 11

OPERATING AND MAINTENANCE EXPENSE
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Schedule 20

Line No.	Particulars	Inflation Indexed O&M	Forecast O&M	Total O&M	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Inflation Indexed O&M**				
2	2022 Base Unit Cost O&M	$ 455			
3	2023 Net Inflation Factor	4.017%			Schedule 3, Line 9, Column 6
4	2023 Base Unit Cost O&M	$ 473			Line 2 x (1 + Line 3)
5					
6	2023 Average Customer Forecast - Rate Setting Purpose	147,901			Schedule 3, Line 22, Column 7
7					
8	2023 Inflation Indexed O&M before prior year True-up	$ 69,957			Line 4 x Line 6 / 1,000
9					
10	2021 Average Customer True-up	509			
11					
12	2023 Inflation Indexed O&M	$ 70,466		$ 70,466	Sum of Lines 8 and 10
13					
14	**O&M Tracked Outside of Formula**				
15	Pension & OPEB (O&M Portion)		$ (1,297)		
16	Insurance Premiums		2,457		
17	BCUC Levies		385		
18	MRS		585		
19	EV Charging Stations		193		
20	Sub-total		$ 2,323	2,323	Sum of Lines 15 through 19
21					
22	**Total Gross O&M**			$ 72,789	Line 12 + Line 20
23	Capitalized Overhead			(10,918)	-15 % x Line 22
24	**Net O&M Expense**			$ 61,871	Sum of Lines 22 and 23

DEPRECIATION AND AMORTIZATION EXPENSE
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Particulars	2022 Approved	2023 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Depreciation**				
2	Depreciation Expense	$ 66,722	$ 69,474	$ 2,752	Schedule 7.1, Line 32, Column 7
3					
4	**Amortization**				
5	Rate Base Deferrals	$ 5,913	$ 6,716	$ 803	Schedule 11, Line 26, Column 6
6	Non-Rate Base Deferrals	(4,355)	(9,993)	(5,638)	Schedule 12.2, Line 23, Column 6
7	Utility Plant Acquisition Adjustment	186	186	-	
8	CIAC	(4,857)	(5,067)	(210)	Schedule 9, Line 7, Column 5
9		(3,113)	(8,158)	(5,045)	
10					
11	Total	$ 63,609	$ 61,316	$ (2,293)	

FORTISBC INC.

FBC Annual Review for 2023 Rates - August 5, 2022

Section 11

Schedule 22

PROPERTY AND SUNDRY TAXES
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Particulars	2022 Approved	2023 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	Generating Plant	$ 3,210	$ 3,253	$ 43	
2	Transmission and Distribution	7,428	7,189	(239)	
3	Substation Equipment	3,948	4,208	260	
4	Land and Buildings	1,165	1,322	157	
5	1% In-Lieu of Municipal Taxes	2,138	2,288	150	
6	Total	$ 17,889	$ 18,260	$ 371	

FORTISBC INC. FBC Annual Review for 2023 Rates - August 5, 2022 Section 11

OTHER REVENUE Schedule 23
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Particulars	2022 Approved	2023 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	Apparatus and Facilities Rental	$ 6,018	$ 6,108	$ 90	
2	Contract Revenue	2,277	2,367	90	
3	Transmission Access Revenue	1,771	1,834	63	
4	Interest Income	20	30	10	
5	Late Payment Charges	875	994	119	
6	Connection Charges	505	553	48	
7	Other Recoveries	366	355	(11)	
8	EV Carbon Credits	-	-	-	
9	Total	$ 11,832	$ 12,241	$ 409	

FORTISBC INC.

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Section 11

Schedule 24

INCOME TAXES
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Particulars	2022 Approved	2023 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**EARNED RETURN**	$ 100,444	$ 108,892	$ 8,448	Schedule 16, Line 19, Column 5
2	Deduct: Interest on Debt	(42,510)	(47,571)	(5,061)	Schedule 26, Line 1+2, Column 7
3	Adjustments to Taxable Income	(37,660)	(45,084)	(7,424)	Line 32
4	Accounting Income After Tax	$ 20,274	$ 16,237	$ (4,037)	
5					
6	1 - Current Income Tax Rate	73.00%	73.00%	0.00%	
7	Taxable Income	$ 27,773	$ 22,242	$ (5,531)	
8					
9	Current Income Tax Rate	27.00%	27.00%	0.00%	
10	Income Tax - Current	$ 7,499	$ 6,005	$ (1,494)	
11					
12	Previous Year Adjustment	-	-	-	
13	**Total Income Tax**	$ 7,499	$ 6,005	$ (1,494)	
14					
15					
16	**ADJUSTMENTS TO TAXABLE INCOME**				
17	Addbacks:				
18	Depreciation	$ 66,722	$ 69,474	$ 2,752	Schedule 21, Line 2, Column 3
19	Amortization of Deferred Charges	1,558	(3,277)	(4,835)	Schedule 21, Line 5+6, Column 3
20	Amortization of Utility Plant Acquisition Adjustment	186	186	-	Schedule 21, Line 7, Column 3
21	Pension Expense	84	(528)	(612)	
22	OPEB Expense	1,607	1,119	(488)	
23					
24	Deductions:				
25	Capital Cost Allowance	(86,398)	(89,854)	(3,456)	Schedule 25, Line 19, Column 6
26	CIAC Amortization	(4,857)	(5,067)	(210)	Schedule 21, Line 8, Column 3
27	Pension Contributions	(4,419)	(4,203)	216	
28	OPEB Contributions	(655)	(705)	(50)	
29	Overheads Capitalized Expensed for Tax Purposes	(10,177)	(10,918)	(741)	Schedule 20, Line 23, Column 4
30	Removal Costs	(1,200)	(1,200)	-	
31	All Other	(111)	(111)	-	
32	Total	$ (37,660)	$ (45,084)	$ (7,424)	

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Schedule 25

CAPITAL COST ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Class	CCA Rate	12/31/2022 UCC Balance	2023 Additions & Opening Adjt	UCC Adjustment for AIIP *	2023 CCA	Forecast 12/31/2023 UCC Balance
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	1(a)	4%	$ 154,085	$ -	$ -	$ (6,163)	$ 147,922
2	1(b)	6%	33,091	3,043	1,521	(2,259)	33,875
3	2	6%	11,403	-	-	(684)	10,719
4	3	5%	648	-	-	(32)	616
5	6	10%	2	-	-	-	2
6	8	20%	3,694	842	421	(991)	3,545
7	10	30%	4,709	1,857	929	(2,250)	4,316
8	13	0%	11	-	-	-	11
9	14.1 (pre 2017)	7%	6,926	-	-	(485)	6,441
10	14.1 (post 2016)	5%	3,951	1,280	640	(294)	4,937
11	17	8%	156,652	22,036	11,018	(15,177)	163,511
12	42	12%	9,649	610	305	(1,268)	8,991
13	43.1	30%	566	(155)	-	(123)	288
14	45	45%	1	-	-	-	1
15	46	30%	2,708	-	-	(812)	1,896
16	47	8%	494,831	87,737	43,868	(50,115)	532,453
17	50	55%	2,800	9,286	4,643	(9,201)	2,885
18							
19	Total		$ 885,727	$ 126,536	$ 63,345	$ (89,854)	$ 922,409
20							
21	* Note - Accelerated Investment Incentive Property						

FORTISBC INC. FBC Annual Review for 2023 Rates - August 5, 2022 Section 11

Schedule 26

RETURN ON CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Particulars	2022 Approved Earned Return	Amount	Ratio	2023 Average Embedded Cost	Cost Component	Earned Return	Earned Return Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	Long Term Debt	$ 41,155	$ 914,178	54.56%	4.78%	2.61%	$ 43,709	$ 2,554	Schedule 27, Line 12, Column 6
2	Short Term Debt	1,355	91,081	5.44%	4.24%	0.23%	3,862	2,507	
3	Common Equity	57,934	670,172	40.00%	9.15%	3.66%	61,321	3,387	
4									
5	Total	$ 100,444	$ 1,675,431	100.00%		6.50%	$ 108,892	$ 8,448	
6									
7	Cross Reference		Schedule 2, Line 29, Column 3						

FORTISBC INC.

FBC Annual Review for 2023 Rates - August 5, 2022

Section 11

Schedule 27

EMBEDDED COST OF LONG TERM DEBT
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Particulars	Issue Date	Maturity Date	Average Principal Outstanding	Interest Rate	Interest Expense	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	1993 Debt Issue - Series G	August 28, 1993	August 28, 2023	$ 16,370	8.800%	$ 1,441	
2	2005 Debt Issue - Series 1 - 05	November 9, 2005	November 9, 2035	100,000	5.600%	5,600	
3	2007 Debt Issue - Series 1 - 07	July 4, 2007	July 4, 2047	105,000	5.900%	6,195	
4	2009 Debt Issue - MTN - 09	June 2, 2009	June 2, 2039	105,000	6.100%	6,405	
5	2010 Debt Issue - MTN - 10	November 24, 2010	November 24, 2050	100,000	5.000%	5,000	
6	2014 Debt Issue - MTN - 14	October 28, 2014	October 28, 2044	200,000	4.000%	8,000	
7	2017 Debt Issue - MTN - 17	December 4, 2017	December 6, 2049	75,000	3.620%	2,715	
8	2020 Debt Issue - MTN - 20	May 11, 2020	May 11, 2050	75,000	3.120%	2,340	
9	2022 Debt Issue - MTN - 22	March 14, 2022	March 14, 2052	100,000	4.160%	4,160	
10	2023 Debt Issue - MTN - 23	July 1, 2023	July 1, 2053	37,808	4.900%	1,853	
11							
12	Total			$ 914,178		$ 43,709	
13							
14	Average Embedded Cost				4.78%		

12. ACCOUNTING MATTERS

12.1 INTRODUCTION AND OVERVIEW

In this section, FBC discusses "Exogenous Factors" under its MRP, providing an update on the exogenous factor treatment for the impacts of the COVID-19 pandemic. FBC also discusses emerging accounting guidance, and the status of its non-rate base deferral accounts. With respect to its non-rate base deferral accounts, FBC provides information on the Flow-through deferral account.

12.2 EXOGENOUS (Z) FACTORS

FBC is permitted to adjust the cost of service for "Exogenous Factors" under the MRP. The BCUC established the following criteria for evaluating whether the impact of an event qualifies for exogenous factor treatment:

1. The costs/savings must be attributable entirely to events outside the control of a prudently operated utility;
2. The costs/savings must be directly related to the exogenous event and clearly outside the base upon which the rates were originally derived;
3. The impact of the event was unforeseen;
4. The costs must be prudently incurred; and
5. The costs/savings related to each exogenous event must exceed the BCUC-defined materiality threshold.

The materiality threshold (item 5) for FBC has been established at $0.150 million, as approved in the MRP Decision.

In the Annual Review for 2020 and 2021 Rates, FBC identified the COVID-19 pandemic as a potential exogenous factor affecting 2020 and future years, and the BCUC approved FBC's request to record COVID-19 pandemic incremental costs and cost reductions from 2020 and 2021 into the previously approved COVID-19 Customer Recovery Fund Deferral Account.[59] FBC also stated in the Annual Review for 2020 and 2021 Rates application that it would review the amounts in 2021 when actual 2020 amounts and forecasts for future years could be ascertained, and an appropriate recovery method could be determined. In the Annual Review for 2022 Rates application, FBC provided a status update on the COVID-19 pandemic net incremental costs (costs less cost reductions). In the following section, FBC reports on the net incremental cost reductions and proposes to return these cost reductions to customers.

[59] FBC Annual Review for 2020 and 2021 Rates Decision and Order G-42-21.

12.2.1 COVID-19 Pandemic

During the COVID-19 pandemic, FBC has taken the necessary steps as a critical infrastructure service provider to ensure the health, safety and well-being of its customers, employees and their communities, and to continue to operate its system safely and reliably. This has resulted in net incremental O&M impacts.

12.2.1.1 FBC Has Reasonably Tracked the Impact of the COVID-19 Pandemic on Net Operating Costs

Consistent with the MRP, FBC's general approach to managing its formula O&M funding is at an overall Company level. O&M funding is prioritized and allocated as required to meet the business environment, conditions and requirements the Company faces. Funding utilized for a specific purpose in one year may be used differently in the following year. As a result, this makes the determination of COVID-19 pandemic net incremental O&M costs from year to year challenging and fluid, particularly for cost reductions, as the Company reprioritizes its funding regularly to meet its needs to provide safe and reliable operations.

Further, the COVID-19 pandemic has a broad impact throughout the organization, making the determination of the incremental costs more challenging. The impact of the COVID-19 pandemic varies in different parts of the business. For example, there may be additional overtime costs in departments that are indirectly influenced by the pandemic (e.g., less internal resources available due to reassignment to assist with other priorities), which are difficult to specifically identify. Also, there may be delays in work scheduled as a result of the pandemic that may increase the total cost of the work required, which are not specifically identified as COVID-19 pandemic related.

Recognizing the above circumstances, FBC has undertaken its best efforts to track and report on the net incremental O&M costs that are directly related to the COVID-19 pandemic. FBC has included below all costs that are specifically identifiable as attributable to activities required to respond to the COVID-19 pandemic as part of the overall net incremental costs (costs less cost reductions). While acknowledging there are uncertainties, the following summary of net incremental cost reductions provides a reasonable representation of the overall COVID-19 pandemic impact on the Company.

12.2.1.2 Summary of Net Incremental Costs

The combined impact in 2020 and 2021 as a result of the COVID-19 pandemic is a decrease by approximately $1.03 million in FBC's net incremental O&M expense (costs less cost reductions).

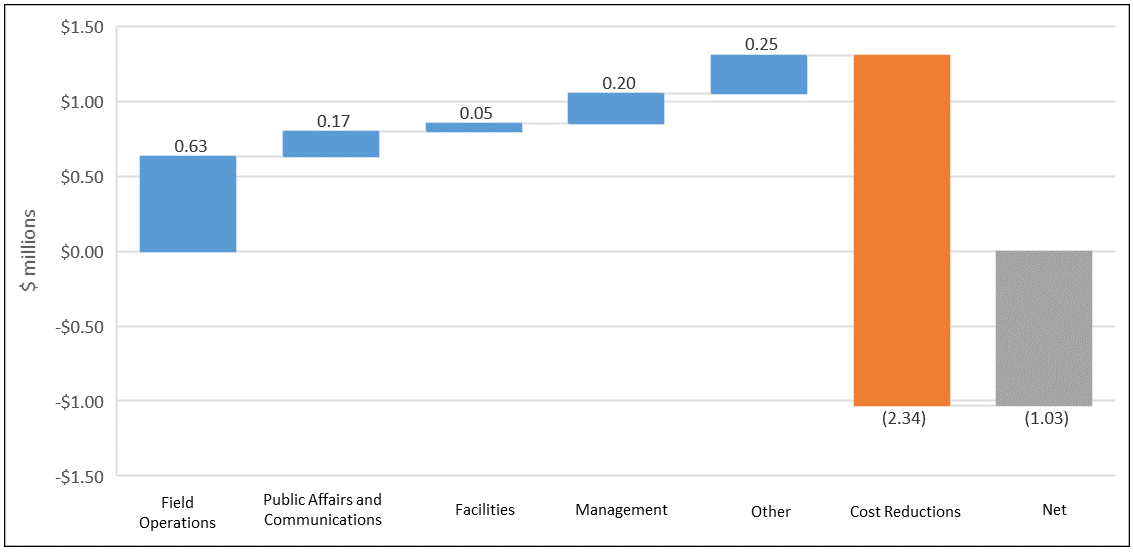
Table 12-1: Net Incremental Cost Reductions ($ millions)

	2020	2021	2020/2021
Direct Costs			
Field Operations	$ 0.46	$ 0.18	$ 0.63
Public Affairs and Communications	$ 0.16	$ 0.01	$ 0.17
Facilities	$ 0.04	$ 0.01	$ 0.05
Management	$ 0.10	$ 0.10	$ 0.20
Other	$ 0.18	$ 0.07	$ 0.25
Total Direct Costs	$ 0.94	$ 0.36	$ 1.31
Cost Reductions	$ (1.05)	$ (1.29)	$ (2.34)
Net difference	$ (0.10)	$ (0.93)	$ (1.03)

12.2.1.3 2020 and 2021 COVID-19 Pandemic Impact

While the COVID-19 pandemic increased many areas of O&M costs in 2020 and 2021, these costs were more than offset by lower employee related expenses. In 2020 and 2021, FBC incurred approximately $1.31 million in O&M costs related to the COVID-19 pandemic. These costs were primarily to ensure the health, safety and well-being of FBC's customers, employees, and their communities, and to continue to operate the system safely and reliably. The incremental costs were offset by approximately $2.34 million in employee expense related reductions. The figure below shows the categories of costs incurred and the offsetting savings. Each of the categories is described further below.

Figure 12-1: FBC COVID-19 Pandemic 2020 and 2021 Net O&M Cost Reductions



12.2.1.3.1 INCREASED O&M EXPENDITURES DUE TO THE COVID-19 PANDEMIC

In the Field Operations area, FBC incurred approximately $0.63 million related to the COVID-19 pandemic, with the majority of the costs related to the sequestering of system control centre employees from having to return to their homes and separation of the operators between the system control centre and Kootenay operating centre sites to ensure a safe and healthy work environment for this critical function. FBC also incurred costs for personal protective equipment (i.e., masks, gloves and sanitizers).

In the Public Affairs and Communications area, FBC incurred approximately $0.17 million for activities to keep customers and key stakeholders informed of the Company's assistance available during the COVID-19 pandemic, including the support required to develop the materials and to monitor and maintain messaging as needed. The costs were for advertising, various communication materials such as bill inserts, and labour and consultant services required to develop the materials and to monitor and maintain messaging as needed.

FBC incurred approximately $0.05 million for Facilities-related resources and activities including safety supplies, additional cleaning, first aid coverage, and signage.

Under the category of Management, approximately $0.20 million in management resource costs were added to support the following areas: the operation of the Emergency Operating Centre (EOC); the Human Resources and Environmental, Health and Safety groups' response to COVID-19 pandemic incidents and issues for employees and contractors; and the increased needs of supporting departments such as Information Systems, Supply Chain, Communications, and Business Continuity. The resources were necessary to respond to the COVID-19 pandemic and to address the various needs of the health authorities, regulators, and organizations like Emergency Management BC.

The Other category of approximately $0.25 million includes miscellaneous items such as different support group costs (e.g., Information Systems and TELUS Babylon health service).

12.2.1.3.2 O&M COST REDUCTIONS OFFSET INCREASED COSTS

The cost reductions that FBC achieved consist primarily of lower employee expenses, in part as a response to the travel restrictions, including in and out of Province travel, and the effect that the COVID-19 pandemic has had on social interactions. Employee expenses that were not incurred include course fees, travel, meals and accommodation, Company function expenses, and employee hiring and relocation expenses.

For the years 2020 and 2021, the reduced employee expenses were estimated at approximately $2.34 million.

12.2.1.3.3 CUMULATIVE NET IMPACT

The variances for the 2020 and 2021 net incremental O&M (costs less cost reductions) total to a net decrease of approximately $1.03 million.

Accordingly, FBC requests approval to return the exogenous factor savings of $1.03 million to customers in 2023, as further described below.

12.2.1.4 2022 COVID-19 Pandemic Impact

With the Company's transition to normal operations, FBC does not anticipate further impacts on its costs in 2022 requiring exogenous factor treatment. As mentioned in FBC's 2022 Annual Review, FBC started the transition to normal operations in September 2021 with the Province achieving Step 4 of the Province of BC Four Step Restart Plan. Step 4 included the lifting of restrictions with normal social contact allowed and workplaces fully reopened. For FBC, this meant having its employees return to offices and worksites starting September 7, 2021 with 100 percent of employees on site at least 50 percent of the time while maintaining building capacity at 50 percent.

The transition to normal operations continued into early 2022 with the provincial government lifting the workplace safety order on April 8, 2022, enabling businesses to transition back to communicable disease plans to reduce risk of all communicable disease, instead of maintaining a COVID-19 safety plan. At the same time, the provincial government also removed restrictions on gatherings and events, including at restaurants, bars, pubs and nightclubs. With the lifting of the workplace safety order, FBC accordingly adjusted its existing COVID-19 safety protocols at its worksites to balance safety with the return to normal operations. The adjustments included suspension of COVID-19 daily health check confirmation and the removal of mandatory mask wearing, although the practice of wearing a mask is still recommended. As of July 4, 2022, employees have returned to a primarily office-based work model. Employee-related activities and expenses for business purposes (i.e., travel, accommodation, etc.) have also returned to normal.

12.2.1.5 Mechanism to Return Cost Reductions to Customers

As part of the Annual Review for 2020 and 2021 Rates, FBC proposed (and was approved by Order G-42-21) to include the amounts related to incremental COVID-19 costs and cost reductions in the previously approved COVID-19 Customer Recovery Fund Deferral Account.

However, upon further review of FBC's original proposal, FBC has concluded that a better approach is to record these amounts in the Flow-through deferral account. This approach is preferable for three reasons:

1. It is consistent with the treatment of other exogenous items;
2. It will allow the O&M reported in the Annual Reports to be more reflective of the actual amounts incurred, as using the Flow-through deferral account does not result in direct adjustments to O&M, but rather one catch-all account for all flow-through adjustments. Alternatively, transferring the actual O&M savings directly to the COVID-19 Customer Recovery Fund Deferral Account would result in those O&M actual amounts being effectively booked back to the forecast amounts; and

3. The COVID-19 incremental savings will be returned to customers immediately in 2023, as opposed to over three years, which is the amortization period being proposed for the COVID-19 Customer Recovery Fund Deferral Account in Section 7.6.2.1.

From a customer perspective, there is no negative impact from the proposed change in treatment as customers will still have the full net savings returned to them. The benefit of the proposed treatment, as described above, is that the net savings will be returned to customers over one year as opposed to three years.

As such, FBC has included the O&M savings shown above in the 2022 Flow-through projection provided in Table 12-3 below, on Line 15, so that the net amount will be returned to customers in 2023 via the amortization of the Flow-through deferral account forecast in this Application.

Accordingly, FBC seeks a variance to Directive 6 of Order G-42-21. FBC requests that Directive 6 be varied as followed: "FBC is approved to record COVID-19 incremental costs and related savings from 2020 and 2021 into the Flow-through deferral account."

12.2.1.6 Conclusion

FBC proposes to refund to customers for years 2020 and 2021, via the Flow-through deferral Account, the cumulative net variance of the net incremental O&M (costs less reductions) of $1.03 million in 2023.

12.3 *ACCOUNTING MATTERS*

In the following section, FBC provides information on emerging accounting guidance.

12.3.1 Emerging Accounting Guidance

In the PBR Plan decision, the BCUC directed FBC to "communicate any accounting policy changes and updates to the Commission and other stakeholders as part of the Annual Review process during the PBR period." While this directive was not included as part of the MRP Decision, FBC will continue to provide accounting policy changes and updates as part of the Annual Review materials.

There are no new accounting policy changes that FBC is proposing, or that are required to be implemented under US GAAP, that result in a change in accounting for 2023; however, FBC provides an update on its exemptive relief to report under US GAAP.

12.3.1.1 Ontario Securities Commission Exemption to use US GAAP

FBC follows US GAAP for both financial and regulatory accounting purposes. Since 2011, FBC has made use of an exemption from the Ontario Securities Commission (OSC) permitting FBC to prepare and file its financial statements in accordance with US GAAP. Like other reporting issuers, FBC also has the option to obtain an exemption permitting the use of US GAAP by

qualifying as a US Securities and Exchange Commission Issuer (SEC Issuer) pursuant to Canadian securities law. During 2022, FBC sought and received approval from its primary securities regulator, the BC Securities Commission (BCSC), for the same exemptive relief as the 2011 OSC exemption. FBC's original exemption from 2011 was filed jointly with FBC's parent company Fortis Inc., whose primary securities regulator is the OSC; however, Fortis Inc. is now an SEC Issuer and no longer makes use of the OSC exemption. As a result, FBC obtained an exemption on a stand-alone basis from the BCSC.

The BCUC has approved FBC's use of US GAAP for regulatory accounting purposes since 2011.[60] As part of the most recent BCUC approval to use US GAAP, the BCUC directed the following:[61]

> Approval is granted until such time as the FortisBC Utilities no longer has an Ontario Securities Commission exemption to use US GAAP or is no longer reporting under US GAAP for financial reporting purposes.

FBC considers that the intention of the above direction was to ensure that FBC has an exemption from its securities regulator to use US GAAP, and not that an exemption specifically from the OSC was required, as opposed to a different securities regulator that had jurisdiction. It was not contemplated at the time of the above direction that FBC would make use of a BCSC exemption rather than an OSC exemption.

To ensure that FBC has approval from the BCUC to use US GAAP for regulatory accounting purposes, FBC is seeking a variance of Directive 2 to Order G-83-14 to remove the reference to the OSC, so that it removes the reference to the Ontario Securities Commission, and states:

> Approval is granted until such time as FBC no longer has an exemption to prepare and file its financial statements in accordance with US GAAP or is no longer reporting under US GAAP for financial reporting purposes.

FBC notes that there have been no other changes in circumstances beyond the change in the regulatory body granting exemptive relief. However, similar to the original 2011 OSC exemptive relief, the 2022 BCSC exemptive relief is not permanent and would expire January 1, 2027 unless extended further. Should FBC plan to no longer report under US GAAP (e.g., convert from US GAAP to IFRS), it would file an application for approval from the BCUC at that time

12.4 *NON-RATE BASE DEFERRAL ACCOUNTS*

FBC maintains both rate base and non-rate base deferral accounts. Rate base deferral accounts are included in rate base and earn a rate base return. In contrast, non-rate base deferral accounts are outside of rate base and may have varying rates of return, depending on the nature of the account and the return approved by the BCUC.

[60] Order G-117-11 dated July 7, 2011 and Order G-83-14 dated July 3, 2014.
[61] Order G-83-14, Directive 2.

In the following section, FBC provides information on its Flow-through deferral account. Information on FBC's non-rate base earnings sharing deferral account is included in Section 10.

12.4.1 New Deferral Accounts

FBC is not seeking approval of any new non-rate base deferral accounts in this Application.

12.4.2 Existing Deferral Accounts

In the section below, FBC discusses the Flow-through deferral account.

12.4.2.1 Flow-Through Deferral Account (2020-2024)

As approved by Order G-166-20, the Flow-through deferral account is used to capture the annual variances between the approved and actual amounts for all costs and revenues which are forecast annually, are not subject to earnings sharing, and which do not have a previously approved deferral account. The specific items included in the Flow-through deferral account were set out in Table C4-1 of the MRP Application, reproduced below.

Table 12-2: Variances Captured in the Flow-through Deferral Account

	FEI	FBC
Delivery Revenues (FEI):		
Residential and commercial use rate variances	RSAM	N/A
Customer variances	Flow-through deferral	N/A
Industrial and all other revenue variances	Flow-through deferral	N/A
Revenues and Power Supply (FBC):		
Revenue variances	N/A	Flow-through deferral
Power Supply variances net of PSI	N/A	Flow-through deferral
Gross O&M:		
Index-based O&M variances	Subject to earnings sharing	Subject to earnings sharing
BCUC fees variances	BCUC variances deferral	BCUC variances deferral
Pension & OPEB variances	Pension/OPEB variances deferral	Pension/OPEB variances deferral
All other O&M variances [1,3]	Flow-through deferral	Flow-through deferral
Capitalized Overhead:		
Capitalized overhead variances	No variance	No variance
Depreciation and Amortization:		
Depreciation rate variances	No variance	No variance
Depreciation on Clean Growth Projects [2,3]	Flow-through deferral	Flow-through deferral
Other depreciation variances	Subject to earnings sharing	Subject to earnings sharing
Amortization of deferrals	No variance	No variance
Property Tax:		
Property tax variances	Flow-through deferral	Flow-through deferral
Other Revenues :		
SCP Mitigation revenues variances	SCP Revenues deferral	N/A
CNG/LNG Recoveries variances	CNG/LNG Recoveries deferral	N/A
Revenues from Clean Growth Projects [2,3]	Flow-through deferral	Flow-through deferral
All other other revenue/income variances	Subject to earnings sharing	Subject to earnings sharing
Interest Expense/Cost of Debt:		
Interest on RSAM/CCRA/MCRA/Gas storage	Interest on RSAM/CCRA/MCRA/Gas Storage	N/A
Interest rate variances	Flow-through deferral	Flow-through deferral
Interest on Clean Growth Projects [2,3]	Flow-through deferral	Flow-through deferral
Other interest variances	Subject to earnings sharing	Subject to earnings sharing
Income Tax:		
Income tax rate variances	Flow-through deferral	Flow-through deferral
Income tax on Clean Growth Projects [2,3]	Flow-through deferral	Flow-through deferral
Other income tax variances	Subject to earnings sharing	Subject to earnings sharing

1: Including items forecast outside of the formula such as insurance premiums, NGT stations, biomethane, variable LNG production, integrity digs and EV charging stations.
2: Cost of service for NGT fueling stations and tankers, variable LNG production, and EV stations will be captured in the Flow-through deferral account.
3: Biomethane other revenues will continue to capture the actual cost of service of the biomethane capital assets and transfer it to the BVA

In accordance with the method set out in the table above, the calculation of the 2022 Projected Flow-through amount of $5.007 million credit is shown in Table 12-3 below. To calculate the amount to be distributed to customers, FBC has also included the following adjustment:

- The $4.618 million credit difference between the projected ending 2021 deferral account credit balance of $3.927 million[62] embedded in 2022 rates, and the actual ending 2021 deferral credit balance of $8.545 million. A more detailed breakout of the 2021 variance is provided in Table 12-4 below. FBC notes that the financing return on this account is included in the aggregate financing of deferral accounts at Section 11, Schedule 12.2, Line 18.

Table 12-3: 2022 Projected Flow-through Deferral Account Additions ($ millions)

Line No.	Particulars	2022 Approved	2022 Projected	After-Tax Flow-Through Variance
	(1)	(2)	(3)	(4)
1	**Total Revenue**	$ (397.294)	$ (414.292)	$ (16.998)
2				
3	**Total Power Purchase Expense**	143.779	153.164	9.385
4				
5	**Total Wheeling**	6.093	6.330	0.237
6				
7	**Total Water Fees**	11.958	11.916	(0.042)
8				
9	**Net O&M Expense**			
10	Pension & OPEB	(1.716)	(1.716)	-
11	Insurance	2.223	2.291	0.068
12	BCUC Fees	0.373	0.373	-
13	MRS	0.765	0.500	(0.265)
14	EV DCFC	0.187	0.187	-
15	COVID-19 Pandemic	-	(1.030)	(1.030)
16	Capitalized Overhead	(10.177)	(10.177)	-
17				
18	**Depreciation and Amortization**			
19	Amortization of Deferrals	1.558	1.558	-
20	Depreciation variance on Clean Growth Projects/CPCNs/Exogenous Capital	-	-	-
21	CIAC Amortization variance on Clean Growth Projects/CPCNs/Exogenous Capital	-	-	-
22				
23	**Total Property Taxes**	17.889	17.621	(0.268)
24				
25	**Other Revenues**			
26	EV Carbon Credits	-	(0.625)	(0.625)
27				
28	**Interest Expense**			
29	Long-term debt interest expense variance	41.155	41.794	0.639
30	Interest variance on Clean Growth Projects/CPCNs/Exogenous Capital	-	-	-
31	Short-term debt rate variance	-	2.253	2.253
32	Short-term debt volume variance from long-term debt issue variance	-	(1.005)	(1.005)
33	Short-term debt timing variance from long-term debt issue timing	-	0.793	0.793
34				
35	**Income Tax Expense**			
36	Income tax variance on Clean Growth Projects/CPCNs/Exogenous Capital	-	-	-
37	Income tax/CCA rate changes	-	-	-
38	Income tax on taxable flowthrough variances above (excl. Clean Growth Projects/CPCNs/Exogenous Capital)	-	1.852	1.852
39				
40	**2022 After-Tax Flow-Through Addition to Deferral Account (excluding Financing)**			**(5.007)**
41				
42	2021 Ending Deferral Account Balance True-up			(4.618)
43				
44	**2023 After-Tax Amortization**			**(9.625)**

[62] FBC Annual Review for 2022 Rates, Compliance Filing financial schedules, Schedule 12.2, Line 4, Column 2.

12.4.2.1.1 2022 PROJECTED FLOW-THROUGH VARIANCES

FBC provides the following explanations for the 2022 Projected flow-through variances shown in Table 12-3 above:

- The variance in revenue is due to increased industrial, commercial, wholesale and residential loads;
- The variance in power purchase expense is primarily due to an increase in gross load. Increasing gross load drove additional market purchases as well as BC Hydro PPA energy and capacity purchases at a higher than anticipated total cost. Rising rates further contributed to the increase in power purchase expense;
- Variances in wheeling and water fees are discussed in Section 4;
- Flow-through O&M amounts are discussed in Section 6;
- Amortization expense is equal to the approved value;
- Variances in property taxes are described in Section 9;
- Variances in other revenues are described in Section 5;
- The projected interest expense variances are derived from FBC issuing long-term debt later in 2022 than forecast, but at a higher amount and higher rate than forecast, and FBC projecting a higher short-term interest rate than the approved short-term interest rate, both as described in Section 8; and
- The income tax variance is derived as 27 percent of the aforementioned variances.

An adjustment to include the difference between the projected and final actual amounts for 2022 subject to flow-through will be recorded in the deferral account in 2022 and amortized in 2024 rates.

12.4.2.1.2 2021 FLOW-THROUGH DEFERRAL ACCOUNT TRUE-UP

As mentioned above, FBC is also providing a breakdown of the 2021 true-up amount of $4.618 million credit in Table 12-4 below, along with an explanation of the variances.

Table 12-4: 2021 Actual vs. Projected Flow-through Deferral Account Additions ($ millions)

Line No.	Particulars	2021 Projected	2021 Actual	After-Tax Flow-Through Variance
	(1)	(2)	(3)	(4)
1	**Total Revenue**	$ (389.100)	$ (404.247)	$ (15.147)
2				
3	**Total Power Purchase Expense**	141.747	152.473	10.726
4				
5	**Total Wheeling**	5.836	6.000	0.164
6				
7	**Total Water Fees**	10.878	10.741	(0.137)
8				
9	**Net O&M Expense**			
10	Pension & OPEB	0.775	0.775	-
11	Insurance	2.022	1.924	(0.098)
12	BCUC Fees	0.350	0.350	-
13	MRS	0.100	0.052	(0.048)
14	2021 Wildfires	0.155	0.155	-
15	Capitalized Overhead	(9.795)	(9.795)	-
16				
17	**Depreciation and Amortization**			
18	Amortization of Deferrals	5.110	5.110	-
19	Depreciation variance on Clean Growth Projects/CPCNs/Exogenous Capital	-	(0.301)	(0.301)
20	CIAC Amortization variance on Clean Growth Projects/CPCNs/Exogenous Capital	-	-	-
21				
22	**Total Property Taxes**	17.225	17.262	0.037
23				
24	**Interest Expense**			
25	Long-term debt interest expense variance	40.698	40.251	(0.447)
26	Interest variance on Clean Growth Projects/CPCNs/Exogenous Capital	-	(0.059)	(0.059)
27	Short-term debt rate variance	(0.500)	(0.593)	(0.092)
28	Short-term debt volume variance from long-term debt issue variance	-	0.303	0.303
29	Short-term debt timing variance from long-term debt issue timing	0.910	-	(0.910)
30				
31	**Income Tax Expense**			
32	Income tax variance on Clean Growth Projects/CPCNs/Exogenous Capital	-	0.048	0.048
33	Income tax/CCA rate changes	-	-	-
34	Income tax on taxable flowthrough variances above (excl. Clean Growth Projects/CPCNs/Exogenous Capital)	1.571	3.097	1.526
35				
36	EV DCFC Service Application 2018-2021 adjustment	0.107	(0.074)	(0.181)
37				
38	**2021 Ending Deferral Account Balance True-up**			**(4.618)**

The 2021 Actual variances shown in Table 12-4 above are described as follows:

- The favourable variance in revenue of $15.147 million was due to higher than projected residential, commercial, wholesale and irrigation loads, mainly due to weather variations. Favourable variances in residential ($12.209 million), commercial ($2.614 million), wholesale ($1.552 million), and irrigation ($0.815 million) revenue were partially offset by unfavourable variances in industrial ($1.939 million) and lighting ($0.104 million) revenue;
- The increase in power purchase expense of $10.726 million was due several factors including increased market expenses, increased load, and reduced generation availability. Increased load and market expenses were primarily due to several extreme weather events, such as the June 2021 heat dome event. This increase was partially offset by increased surplus capacity sales under the CEPSA Agreement;
- The increase in wheeling costs of $0.164 million was primarily due to increased use of wheeling under BC Hydro's Open Access Transmission Tariff;
- The decrease in water fees of $0.137 million was primarily due to reduced water rental rates compared to forecast;

- The flow-through components of O&M expense were $0.146 million lower than projected, with all items comparable to the projected amounts;
- Actual property tax expense was relatively consistent with the projected amount;
- The variance between the actual (0.81 percent) and projected (1.03 percent) short-term debt interest rates results in an amount to be returned to customers of $0.092 million,[63] shown on Line 27 of the table above. The long-term debt interest expense variance of $0.447 million to be returned to customers is due to the projected 2021 long-term debt issuance not actually occurring. The net variance of $0.607 million to be returned to customers on Lines 28 and 29 of Table 12-4 above is due to the impact of a lower actual short-term interest rate than projected, partially offset by the delay in the 2021 long-term debt issuance;
- The unfavourable income tax variance of $1.526 million is calculated as 27 percent of the aforementioned variances;
- The favourable variance of $0.181 million for the EV DCFC Service Application 2018-2021 adjustment relates to the true-up of the 2021 cost of service amounts. As discussed in the Compliance Filing to the 2022 Annual Review Decision, FBC estimated the 2018-2021 EV cost of service amounts to be a $0.107 million debit recoverable from customers, using the 2018-2020 actual cost of service amounts and a 2021 projected amount. The actual 2021 EV cost of service was lower than projected, mainly related to favourable taxes, resulting in the $0.181 million overall credit true-up amount to be returned to customers; and
- The combined favourable variance of $0.312 million related to depreciation, CIAC amortization, interest and tax variances on Clean Growth/CPCN/exogenous capital amounts, shown on Lines 19, 20, 26 and 32, respectively, were derived for 2021 by comparing the actual 2021 cost of service impacts of the UBO, Grand Forks Terminal Station and Corra Linn projects to the amounts forecast for those same projects.

12.5 *SUMMARY*

FBC has requested approval to return the incremental net cost reductions related to the COVID-19 pandemic exogenous factor to customers in 2023 through inclusion in the Flow-through deferral account. FBC has also provided an update on certain accounting related matters, and included information on the Flow-through deferral account.

[63] (0.81% - 1.03%) x $42.042 million forecast 2021 short-term debt in Schedule 26 of October 28, 2020 Evidentiary Update financial schedules.

13. SERVICE QUALITY INDICATORS

13.1 INTRODUCTION AND OVERVIEW

Under the MRP, SQIs are used to monitor the Utility's performance to ensure that any efficiencies and cost reductions do not result in a degradation of the quality of service to customers.

In the MRP Decision and Order G-166-20, the BCUC approved a balanced set of SQIs for FBC, covering safety, responsiveness to customer needs, and reliability. Eight of the SQIs have benchmarks and performance ranges set by a threshold level. Four of the SQIs are for information only and as such do not have benchmarks or performance ranges.

In the subsections below, FBC reports on its 2021 and June 2022 year-to-date performance as measured against the SQI benchmarks and thresholds. In 2021, for the eight SQIs with benchmarks, six met or were better than the benchmark, with two better than the threshold. For the four SQIs that are informational only, performance in 2021 generally remains at a level consistent with prior years. In 2022 to date, performance for the metrics with benchmarks are trending towards meeting the benchmark or the threshold.

Consistent with how SQIs were reviewed during the 2014-2019 PBR Plan term,[64] FBC has provided 2021 and year-to-date 2022 SQI results in this annual review. In accordance with Order G-44-16, the BCUC will evaluate FBC's actual 2022 SQI performance in the Annual Review for 2024 Rates when actual SQI results are known. FBC also notes that it will provide information on the 2023 year-to-date SQI results in the Annual Review for 2024 Rates.

13.2 REVIEW OF THE PERFORMANCE OF SERVICE QUALITY INDICATORS

For each SQI, Table 13-1 provides a comparison of FBC's 2021 and June year-to-date performance for 2022 to the proposed benchmarks and thresholds approved as part of the MRP. Actual 2021 and June year-to-date results for 2022 are also provided for the four informational SQIs.

[64] MRP Decision page 99: "the Panel determines that the existing approved process for interpreting metric performance is to remain in effect over the term of the MRPs."

Table 13-1: Approved SQIs, Benchmarks and Actual Performance

Performance Measure	Description	Benchmark	Threshold	2021 Results	June 2022 YTD Results
Safety SQIs					
Emergency Response Time	Percent of calls responded to within two hours	>=93%	90.6%	93%	95%
All Injury Frequency Rate (AIFR)	3 year average of lost time injuries plus medical treatment injuries per 200,000 hours worked	<=1.64	2.39	0.67	0.80
Responsiveness to Customer Needs SQIs					
First Contact Resolution	Percent of customers who achieved call resolution in one call	>=78%	74%	82%	78%
Billing Index	Measure of customer bills produced meeting performance criteria	<=3.0	5.0	0.12	0.14
Meter Reading Accuracy	Number of scheduled meters that were read	>=98%	96%	99%	99%
Telephone Service Factor (Non-Emergency)	Percent of non-emergency calls answered within 30 seconds or less	>=70%	68%	70%	63%
Customer Satisfaction Index	Informational indicator - measures overall customer satisfaction	-	-	8.4	8.4
Average Speed of Answer	Informational indicator – the amount of time it takes to answer a call (seconds)	-	-	65	98
Reliability SQIs					
System Average Interruption Duration Index (SAIDI) – Normalized	Annual SAIDI (average of cumulative customer outage time)	3.22[65]	4.52	4.27	2.94
System Average Interruption Frequency Index (SAIFI) - Normalized	Annual SAIFI (average customer outage)	1.57	2.19	2.08	1.58
Generator Forced Outage Rate	Informational indicator – Percent of time a generating unit is removed from service due to component failure or other events.	-	-	0.23%	0.85%
Interconnection Utilization	Informational indicator – percent of time that an interconnection point was available and providing electrical service to wholesale customers.	-	-	99.90%	99.91%

[65] Benchmarks and thresholds for SAIDI and SAIFI were approved in the FBC Annual Review for 2020 and 2021 Rates Decision and Order G-42-21.

In the following sections, FBC reviews each SQI's year-to-date individual performance in 2021 and 2022. Discussion is also provided for the informational SQIs.

13.2.1 Safety Service Quality Indicators

13.2.1.1 Emergency Response Time

Emergency Response Time is the time elapsed from the initial identification of a loss of electrical power (via a customer call or internal notification) to the arrival of FBC personnel on site at the trouble location. This metric provides ongoing information to assess FBC crew sizes and crew locations in response to system trouble. The target measures the percentage of emergency calls responded to within two hours. The measure is calculated as follows:

$$\frac{\text{Number of emergency calls responded to within two hours}}{\text{Total number of emergency calls in the year}}$$

There are many variables affecting the response time, including time of day (i.e., during business hours or after business hours), number and type of events (i.e., widespread outages), available resources, location (i.e., travel times and traffic congestion) and weather conditions.

The 2021 result was 93 percent which met the benchmark. The June 2022 year-to-date performance is 95 percent, which is better than the benchmark.

For comparison, the Company's annual results under the 2014-2019 PBR Plan, the 2020 and 2021 results and the June 2022 year-to-date emergency response time results are provided below. While the results have been relatively consistent, variables such as the location and severity of outage and the number of trouble calls contribute to the observed volatility in the annual performance for this metric.

Table 13-2: Historical Emergency Response Time

Description	2014	2015	2016	2017	2018	2019	2020	2021	June 2022 YTD
Results	91%	92%	97%	93%	94%	92%	92%	93%	95%
Benchmark	93%								
Threshold	90.6%								

13.2.1.2 All Injury Frequency Rate

The All Injury Frequency Rate (AIFR) is an employee safety performance indicator based on injuries per 200,000 hours worked, with injuries defined as lost time injuries (i.e., one or more days missed from work) and medical treatments (i.e., medical treatment was given or prescribed). The annual performance for this metric is calculated as:

$$\frac{\text{Number of Employee Injuries x 200,000 hours}}{\text{Total Exposure Hours Worked}}$$

For the purpose of this SQI, the measurement of performance is based on the three-year rolling average of the annual results.

The 2021 (three-year rolling average) result was 0.67 which was better than the benchmark of 1.64. The 2021 annual AIFR was 0.89 which reflected 3 Medical Treatments and 1 Lost Time Injury.

The June 2022 year-to-date performance (three-year rolling average) result is 0.80 which is better than the benchmark. The June 2022 year-to-date performance (annual) is 1.25 and reflects 2 Medical Treatments and 1 Lost Time Injury.

Strengthening the safety culture continues to be a key driver for FBC, building on the commitment to learn from safety events, identify safety hazards, assess risk and continually improve through the implementation and sustainment of robust safety barriers and controls.

For comparison, the Company's results under the 2014 to 2019 PBR Plan, the 2020 and 2021 results and the June 2022 year-to-date AIFR results are provided below.

Table 13-3: Historical All Injury Frequency Rate Results

Description	2014	2015	2016	2017	2018	2019	2020	2021	June 2022 YTD
Annual Results	3.21	1.54	1.15	1.13	1.56	0.46	0.66	0.89	1.25
Three year rolling average	2.58	2.52	1.97	1.27	1.28	1.06	0.87	0.67	0.80
Benchmark	1.64								
Threshold	2.39								

13.2.2 Responsiveness to Customer Needs Service Quality Indicators

13.2.2.1 First Contact Resolution

First Contact Resolution (FCR) measures the percentage of customers who receive resolution to their issue in one contact with FBC. The Company determines the FCR results using a customer survey, tracking the number of customers who responded that their issue was resolved in the first contact with the Company. The FCR rate is impacted by factors such as the quality and effectiveness of the Company's coaching and training programs and the composition of the different call drivers.

The 2021 result was 82 percent which was better than the benchmark of 78 percent. The June 2022 year-to-date performance is 78 percent which meets the benchmark.

For comparison, the Company's results under the 2014 to 2019 PBR Plan, the 2020 and 2021 results and the June 2022 year-to-date results are provided below.

Table 13-4: Historical First Contact Resolution Levels

Description	2014	2015	2016	2017	2018	2019	2020	2021	June 2022 YTD
Annual Results	73%	76%	79%	80%	82%	82%	82%	82%	78%
Benchmark	78%								
Threshold	72%						74%		

13.2.2.2 Billing Index

The Billing Index indicator tracks the effectiveness of the Company's billing system by measuring the percentage of customer bills produced meeting performance criteria. The Billing Index is a composite index with three components:

- Billing completion (percent of accounts billed within two days of the billing due date);
- Billing timeliness (percent of invoices delivered to Canada Post within two days of file creation); and
- Billing accuracy (percent of bills without a production issue based on input data).

The objective is to achieve a score of five or less.

The Billing Index is impacted by factors such as the performance of the Company's billing system, weather variability, which can cause a high volume of billing checks and estimation issues, and mail delivery by Canada Post.

The 2021 result was 0.12 which was better than the benchmark of 3.0. No significant billing issues occurred in 2021. The June 2022 year-to-date result is 0.14, which is also better than the benchmark.

The 2021 Billing Index sub-measures calculation is as follows.

Table 13-5: Calculation of 2021 Billing Index

Billing sub-measure	Percent Achieved (PA)	Formula		Result
Billing Accuracy (Percent of bills without a Production Issue, based on input data); Target: 99.9%	100.00%	If (PA≥99.9%,5000*(1 - PA),100*(1.05-PA))	=5000*(1-99.99885%)	0.06

Billing sub-measure	Percent Achieved (PA)	Formula		Result
Billing Timeliness (Percent of invoices delivered to Canada Post within 2 days of file creation); Target: 95%	100.00%	(100%-PA)*100	=(100%-100%)*100	0.00
Billing Completion (Percent of accounts billed within 2 days of the billing due date); Target: 95%	99.60%	(100%-PA)*100	=(100%-99.69%)*100	0.31
Billing Service Quality Indicator; Target < 3.0		(Accuracy PA+Timeliness PA+Completion PA)/3	=(0.06+0+0.31) /3	0.12

For comparison, the Company's results under the 2014 to 2019 PBR Plan, the 2020 and 2021 results and the June 2022 year-to-date results are provided below.

Table 13-6: Historical Billing Index Results

Description	2014	2015	2016	2017	2018	2019	2020	2021	June 2022 YTD
Annual Results	2.34	0.39	0.57	0.15	0.29	1.96	0.13	0.12	0.14
Benchmark	5.0						3.0		
Threshold	5.0								

13.2.2.3 Meter Reading Accuracy

This SQI compares the number of meters that are read to those scheduled to be read. Providing accurate and timely meter reads for customers is a key driver for the Company and its customers. The results are calculated as:

$$\frac{\text{Number of scheduled meters read}}{\text{Number of scheduled meters for reading}}$$

The 2021 result was 99 percent, which was better than the benchmark of 98 percent. The June 2022 year-to-date result is 99 percent, which is better than the benchmark.

For comparison, the Company's results under the 2014 to 2019 PBR Plan, the 2020 and 2021 results and the June 2022 year-to-date results are provided below.

Table 13-7: Historical Meter Reading Accuracy Results

Description	2014	2015	2016	2017	2018	2019	2020	2021	June 2022 YTD
Annual Results	98%	96%	99%	99%	99%	99%	99%	99%	99%
Benchmark	97%						98%		
Threshold	94%						96%		

13.2.2.4 Telephone Service Factor (Non-Emergency)

The Telephone Service Factor (Non-Emergency) measures the percentage of non-emergency calls that are answered in 30 seconds. It is calculated as:

$$\frac{\text{Number of non-emergency calls answered within 30 seconds}}{\text{Number of non-emergency calls received}}$$

The TSF is a measure of how well the Company can balance costs and service levels with the overall objective to maintain a consistent TSF level. This ensures the Company is staying within appropriate cost levels and maintaining adequate service for its customers. The principal factors influencing the TSF results include volume and type of inbound calls received and the resources available to answer those calls. Staffing is matched to the expected call volume based on historical data in order to reach the service level benchmark desired. Other factors that can influence the TSF are billing system related issues and weather patterns that may generate high numbers of billing related queries and the complexity of the calls.

The 2021 result was 70 percent which met the benchmark. The June 2022 year-to-date performance is 63 percent, which is below the threshold.

Several challenging circumstances were faced in the first quarter of 2022 that have contributed to a year-to-date performance in the non-emergency TSF below threshold. These challenges include higher than normal attrition levels being experienced in the contact centre coupled with colder weather that resulted in approximately 27 percent more high bill inquiries in the first quarter than the average of the preceding two years[66]. Each of these is described further below.

Customer Service is experiencing higher than expected levels of attrition, having lost approximately 20 percent of its Customer Service Representatives in 2021.[67] All exits were in the last half of 2021, resulting in fewer and less experienced employees prepared to support call volumes in the first quarter of 2022. To mitigate the impact of this, FBC accelerated the timing of planned new hire classes as well as the size of new hire classes in both 2021 and 2022. While

[66] FBC experienced approximately 1,000 high bill inquiries in Q1 2022 which compares to an average of approximately 790 in the first quarter for the two-year period 2020-2021.

[67] On average, FBC has approximately 20 customer service representatives, and 4 left the organization in the latter part of 2021. This compares to typical annual attrition in the range of 1-2 customer service representatives from the organization.

some success has been achieved, FBC has continued to face challenges recruiting and retaining newly hired contact centre employees in 2022. In addition, it takes on average approximately 12 months for new employees to be proficient and fully trained in order to support all customer inquiries and calls, and as such, average call handle times remain higher than normal while a greater portion of employees gain this experience.

High bill inquiries are expected in the first quarter of the year and planned for with staffing levels and schedules adjusted, new hire classes timed accordingly, and refresher training offered to those employees who may need it. However, the colder temperatures resulted in a volume of high bill inquiries that was greater than anticipated and lasted longer than typical, carrying into April instead of early March. This particular call type is often longer in duration and may also result in follow-up work and investigation. As noted above, there were fewer and less experienced employees prepared to support these types of calls. Thus, the contact centre experienced the compounding impact of fewer employees along with a higher volume of this call type, resulting in overall longer average wait times and a lower percentage of calls answered within thirty seconds or less.

Although the start of 2022 has been challenging, strong performance in first contact resolution, in addition to the promotion of self-service and the call back feature, continues to mitigate the impacts of lower TSF on customer experience and service quality. Further, the recovery of the non-emergency TSF remains a focus, with FBC expecting to recover to threshold levels on a year-to-date basis within the fourth quarter. Finally, the customer service index has remained high throughout 2021 and 2022 to date, indicating that the mitigation measures and focus on first contact resolution continue to result in an overall high quality of service being experienced by customers.

For comparison, the Company's results under the 2014 to 2019 PBR Plan, the 2020 and 2021 results and the June 2022 year-to-date results are provided below. As discussed in the Annual Review for 2015 Rates, the 2014 result was negatively impacted by events such as the first verified meter readings occurring after the IBEW labour disruption ended in December 2013, introduction of the Residential Conservation Rate, and the integration of the City of Kelowna customers.

Table 13-8: Historical TSF Results

Description	2014	2015	2016	2017	2018	2019	2020	2021	June 2022 YTD
Annual Results	48%	71%	70%	70%	72%	70%	70%	70%	63%
Benchmark					70%				
Threshold					68%				

13.2.2.5 Customer Satisfaction Index

The Customer Satisfaction Index (CSI) is an informational indicator that measures overall customer satisfaction with the Company. The index reflects customer feedback about important service touch points including the contact centre, perceived accuracy of meter reading, energy conservation information and field services. The index includes feedback from both residential and commercial customers. The survey is conducted quarterly, and results are presented as a score out of ten.

The CSI survey investigates service quality as well as customer attitudes that are often influenced by factors outside the Company's control. Important examples include storm-related unplanned outages and media coverage.

The annual CSI score for 2021 was 8.4, slightly lower than that obtained in 2020. There were no statistically significant shifts from 2020 to 2021 in the five measures that make up the overall customer satisfaction score. The score for overall satisfaction, which has the highest weighting, decreased from 8.5 in 2020 to 8.4 in 2021. The scores for satisfaction with the energy conservation information and contact centre metrics decreased from 7.6 in 2020 to 7.5 in 2021, and 8.5 in 2020 to 8.4 in 2021, respectively. In addition, the scores for the satisfaction with the accuracy of meter reading and field services metrics remained static at 8.2 and 9.0 in 2021, respectively.

The score for 2022 year-to-date is 8.4, consistent with the annual score recorded for 2021. Of the five measures that make up the overall customer satisfaction score, the results for June 2022 year-to-date were higher in one area, lower in one, and static in three when compared to the annual 2021 scores. The score for the satisfaction with the accuracy of meter reading metric increased from 8.2 to 8.3. The score for the satisfaction with field services metric decreased from 9.0 to 8.8. The scores for the overall satisfaction, energy conservation information, and contact centre metrics were static at 8.4, 7.5 and 8.4, respectively, from results achieved in 2021. None of these changes are statistically significant.

For comparison, the Company's results under the 2014 to 2019 PBR Plan, the 2020 and 2021 results and the June 2022 year-to-date results are provided below.

Table 13-9: Historical Customer Satisfaction Results

Description	2014	2015	2016	2017	2018	2019	2020	2021	June 2022 YTD
Annual Results	8.1	8.1	8.2	8.2	8.3	8.5	8.5	8.4	8.4
Benchmark	n/a								
Threshold	n/a								

13.2.2.6 Average Speed of Answer

The Average Speed of Answer (ASA) is an informational indicator that measures the amount of time it takes for a customer service representative to answer a customer's call (seconds).

The 2021 result was 65 seconds, and the June 2022 year-to-date performance is 98 seconds.

As with previous years, 2021 remained within a reasonable range from a customer experience perspective in that, on average, calls to the contact centre were answered in and around the one-minute mark. With respect to 2022, the year-to-date performance reflects the challenging circumstances in the first quarter of the year described above for the Telephone Service Factor (Non-Emergency). Recovery of the ASA back towards normal performance is expected to continue through the remainder of the year.

For comparison, the Company's results under the 2014 to 2019 PBR Plan, the 2020 and 2021 results and the June 2022 year-to-date results are provided below.[68]

Table 13-10: Average Speed of Answer

Description	2014	2015	2016	2017	2018	2019	2020	2021	June 2022 YTD
Annual Results	226	49	48	49	49	49	71	65	98
Benchmark	n/a								
Threshold	n/a								

13.2.3 Reliability Service Quality Indicators

FBC measures transmission and distribution system reliability according to the Institute of Electrical and Electronics Engineers (IEEE) method of normalizing reliability statistics by excluding "major events". Major events are identified as those that cause outages exceeding a threshold number of customer-hours. Threshold values are calculated by applying a statistical method called the "2.5 Beta" adjustment to historical reliability data. Any single outage event that exceeds the threshold value is excluded from the reliability data. Excluding major events allows them to be studied separately and reveals trends in daily operations that would be hidden or skewed if they were included in the data set. Major event days in the FBC service territory have been caused by mudslides, wind or snow storms, and wildfires.

Reported outages included in these measures are of one minute or longer in duration, which is consistent with the Canadian Electricity Association (CEA) standard for reporting.

[68] ASA in 2014 is higher than other years due to the impact of the six months of job action that took place in Q3 and Q4 of 2013. This job action resulted in a higher number of bill estimates, which led to a higher volume of customer inquiries in 2014 as bill adjustments were made reflecting actual meter reads.

13.2.3.1 System Average Interruption Duration Index (SAIDI) – Normalized

SAIDI is the amount of time the average customer's power is off during the year (i.e., the total amount of time the average customer's clock would lose during a year), after adjusting for the impact of major events as described above, and is calculated as follows:

$$\frac{\text{Total Customer Hours of Interruption}}{\text{Total Number of Customers Served}}$$

Customer Hours of Interruption related to a power outage are calculated by multiplying the number of customers affected by the outage by the duration of the outage.

For the purpose of this SQI, the measurement of performance is based on the annual results.

The 2021 result was 4.27 which was better than the threshold of 4.52 but below the benchmark of 3.22. The June 2022 year-to-date performance is 2.94 which is better than the benchmark. The 2021 results were negatively impacted by multiple external factors which did not meet the threshold for normalization.

The July 2021 results were nearly five times the three-year average and were heavily influenced by several factors that did not meet the threshold for normalization. The largest single event that influenced the July results was the collapse of a construction crane on July 12 in downtown Kelowna. The immediate response to this event was to de-energize a large portion of the surrounding area so that first responders could safely attend to the scene. This incident interrupted power to over 2,600 customers and accounted for over 36,000 customer hours interrupted.

British Columbia also experienced an unprecedented run of extreme heat at the end of June and early July which dried forest fuels earlier than usual and led to one of the worst fire seasons on record. FBC transmission and distribution infrastructure were both impacted by the wildfires with dozens of structures burned to the ground. The largest single outage due to these fires was in the Oliver area and contributed over 21,000 customer hours to July.

In addition to the damaged infrastructure, FBC Operations proactively de-energized portions of the system at the request of BC Wildfire Services to assist in fire suppression efforts. System operations were also impacted by proactively disabling automatic line reclosing in parts of the system to reduce the risk of igniting a fire from trees contacting FBC lines. This led to larger and longer outages in areas of the system where automatic line reclosing was disabled to allow field crews time to assess the cause and confirm that it was safe to re-energize the system. FBC estimates that the combination of fire damage, proactive de-energization, and disabling of automatic line reclosing contributed to over 52,000 customer hours of interruption in July.

There were three Major Event Days that met the threshold for normalization in 2021:

- On January 13, a major windstorm across the Okanagan and Kootenays caused approximately 11,000 customer-interruptions and totalled over 155,000 customer-hours of interruption.
- On April 18, a major windstorm across the West Kootenays qualified for a Major Event Day causing approximately 19,800 customer-interruptions and totalled over 200,800 customer-hours of interruption.
- On November 15, a major storm affected multiple areas in the Okanagan causing approximately 27,474 customer-interruptions and totalled over 218,720 customer-hours of interruption. This event is the highest total customer-hours of interruption FBC has on record (back to 2003).

There have been no Major Event Days in 2022 to-date.

For comparison, the Company's results under the 2014 to 2019 PBR Plan, the 2020 and 2021 results and the June 2022 year-to-date results are provided below. From 2014 to 2019, the benchmark and the threshold reflect the values established under the PBR Plan using three-year rolling average results. Starting in 2020, the benchmark and threshold reflect the values approved by the BCUC for the MRP term.[69]

Table 13-11: Historical SAIDI Results

Description	2014	2015	2016	2017	2018	2019	2020	2021	June 2022 YTD
Annual normalized results	2.32	2.13	2.10	4.05	3.15	2.45	3.17	4.27	2.94
Benchmark	2.22						3.22		
Threshold	2.62						4.52		

13.2.3.2 System Average Interruption Frequency Index (SAIFI) – Normalized

SAIFI is the average number of interruptions per customer served per year (i.e., the number of times the average customer would have to reset their clock during the year), after adjusting for the impact of major events as described above, and is calculated as follows:

$$\frac{\text{Total Number of Customer Interruptions}}{\text{Total Number of Customers Served}}$$

The Number of Customer Interruptions related to a power outage is the number of customers affected by the outage.

[69] The benchmark and threshold for SAIDI were approved in the FBC Annual Review for 2020 and 2021 Rates Decision and Order G-42-21.

For the purpose of this SQI, the measurement of performance is based on the annual results.

The 2021 result was 2.08 and the June 2022 year-to-date performance is 1.58, with both better than the threshold of 2.19. The 2021 results for SAIFI were similarly impacted by the crane collapse, wildfires and storms that were discussed in the SAIDI section. FBC also completed system upgrades on several radial transmission lines where no alternate supply was available which impacted a large number of customers. These outages were scheduled in advance during "off peak" hours to minimize the impact to homes and businesses.

For comparison, the Company's results under the 2014 to 2019 PBR Plan, the 2020 and 2021 results and the June 2022 year-to-date results are provided below. From 2014 to 2019, the benchmark and the threshold reflect the values established under the PBR Plan using three-year rolling average results. Starting in 2020, the benchmark and threshold reflect the values approved by the BCUC for the MRP term.[70]

Table 13-12: Historical SAIFI Results

Description	2014	2015	2016	2017	2018	2019	2020	2021	June 2022 YTD
Annual normalized results	1.64	1.56	1.34	1.78	1.73	1.21	1.64	2.08	1.58
Benchmark	1.64						1.57		
Threshold	2.50						2.19		

13.2.3.3 Generator Forced Outage Rate

Generator Forced Outage Rate (GFOR), an informational indicator, is a measure of the percentage of time in one year that the generating units experienced forced outages compared to the amount of time they could have operated without a forced outage. A forced outage means the removal of a generating unit from service due to the occurrence of a component failure or other event, making it unavailable to produce power due to the unexpected breakdown. The GFOR is defined by the CEA as follows:

$$\frac{\text{Total Forced Outage Time}}{\text{Total Forced Outage Time + Total Operating Time}} \times 100$$

The 2021 result for GFOR was 0.23 percent. The June 2022 year-to-date performance is 0.85 percent.

For comparison, the Company's results under the 2014 to 2019 PBR Plan, the 2020 and 2021 results and the June 2022 year-to-date results are provided below.

[70] The benchmark and threshold for SAIFI were approved in the FBC Annual Review for 2020 and 2021 Rates Decision and Order G-42-21.

Table 13-13: Historical Generator Forced Outages

	2014	2015	2016	2017	2018	2019	2020	2021	June 2022 YTD
FBC	1.7%	0.1%	0.8%	0.6%	0.4%	0.1%	1.3%	0.23%	0.85%
CEA	6.3%	6.2%	6.2%	6.2%	6.7%	4.9%	4.60	TBD	

13.2.3.4 Interconnection Utilization

Interconnection Utilization, an informational indicator, is a measurement of the time that an interconnection point was available and providing electrical service to the municipal wholesale customers (City of Penticton, City of Summerland, City of Grand Forks and City of Nelson). There are twelve points of interconnection combined between the four customers.

The Interconnection Utilization metric for the interconnection points listed is calculated as follows:

$$\frac{\text{Total Operating Hours}}{\text{Total Operating Hours + Total Outage Time}}$$

The 2021 result of 99.90 percent and June 2022 year-to-date result of 99.91 percent are generally consistent with prior years' results. The City of Nelson interconnection at Coffee Creek was negatively impacted by two of the three Major Events on the FBC system described previously in the SAIDI section. For comparison, the Company's results under the 2014 to 2019 PBR Plan, the 2020 and 2021 results and the June 2022 year-to-date results are provided below.

Table 13-14: Interconnection Utilization

Description	2014	2015	2016	2017	2018	2019	2020	2021	June 2022 YTD
Interconnection Utilization	99.99%	99.94%	99.99%	99.95%	99.96%	99.98%	99.89%	99.90%	99.91%
Benchmark	n/a								
Threshold	n/a								

13.3 *SUMMARY*

In summary, FBC's 2021 and June 2022 year-to-date SQI results indicate that the Company's overall performance meets service quality requirements. In 2021, for the eight SQIs with benchmarks, six met or were better than the benchmark with two better than the threshold. For the four SQIs that are informational only, performance in 2021 generally remains at a level consistent with prior years.

Appendix A
LOAD FORECAST SUPPLEMENTARY INFORMATION

Table A1-1: Consumer Price Index (CPI)

Products and product groups[3, 4]	All-items
Reference period	
	2002=100
July 2020	132.6
August 2020	132.4
September 2020	132.5
October 2020	132.9
November 2020	133.3
December 2020	132.8
January 2021	133.6
February 2021	134.1
March 2021	134.9
April 2021	135.2
May 2021	135.1
June 2021	135.8
July 2021	136.7
August 2021	137.0
September 2021	137.2
October 2021	137.9
November 2021	138.1
December 2021	138.0
January 2022	139.4
February 2022	140.4
March 2022	143.0
April 2022	144.2
May 2022	146.1
June 2022	146.5

Table A1-2: Average Weekly Earnings (AWE)

North American Industry Classification System (NAICS)[5]		Industrial aggregate excluding unclassified businesses[6, 7]
Geography	Reference period	
		Dollars
British Columbia (map)	July 2020	1,093.72[B]
	August 2020	1,089.35[B]
	September 2020	1,093.75[B]
	October 2020	1,095.32[B]
	November 2020	1,102.95[B]
	December 2020	1,110.36[B]
	January 2021	1,113.22[B]
	February 2021	1,114.21[B]
	March 2021	1,107.66[B]
	April 2021	1,112.04[B]
	May 2021	1,118.59[B]
	June 2021	1,115.40[B]
	July 2021	1,140.52[B]
	August 2021	1,142.40[B]
	September 2021	1,139.64[B]
	October 2021	1,136.85[B]
	November 2021	1,132.25[B]
	December 2021	1,134.84[B]
	January 2022	1,157.19[B]
	February 2022	1,153.88[B]
	March 2022	1,161.22[B]
	April 2022	1,176.54[B]

Table A1-3: British Columbia Two-Year Outlook 2022

Key Economic Indicators: British Columbia, 2021-23
(forecast completed February 18, 2022)

	2021Q1	2021Q2	2021Q3	2021Q4	2022Q1	2022Q2	2022Q3	2022Q4	2023Q1	2023Q2	2023Q3	2023Q4	2021	2022	2023
GDP at market prices ($ millions)	328,577	329,385	334,551	339,673	343,417	348,045	350,673	353,935	356,447	359,588	361,919	364,178	333,047	349,017	360,533
	1.5	*0.2*	*1.6*	*1.5*	*1.1*	*1.3*	*0.8*	*0.9*	*0.7*	*0.9*	*0.6*	*0.6*	*7.7*	*4.8*	*3.3*
GDP at market prices (2012 $ millions)	278,978	277,225	279,564	281,275	283,897	288,030	290,551	293,351	295,260	297,122	298,139	299,057	279,261	288,957	297,395
	0.7	*-0.6*	*0.8*	*0.6*	*0.9*	*1.5*	*0.9*	*1.0*	*0.7*	*0.6*	*0.3*	*0.3*	*4.7*	*3.5*	*2.9*
GDP at basic prices (2012 $ millions)	258,225	257,607	258,824	259,977	262,651	266,678	269,275	272,107	273,828	275,566	276,523	277,352	258,659	267,678	275,817
	0.5	*-0.2*	*0.5*	*0.4*	*1.0*	*1.5*	*1.0*	*1.1*	*0.6*	*0.6*	*0.3*	*0.3*	*4.8*	*3.5*	*3.0*
Consumer price index (2002 = 1.000)	1.342	1.354	1.370	1.380	1.401	1.412	1.424	1.433	1.441	1.449	1.456	1.463	1.361	1.418	1.452
	0.9	*0.9*	*1.2*	*0.7*	*1.6*	*0.7*	*0.9*	*0.6*	*0.6*	*0.6*	*0.5*	*0.5*	*2.8*	*4.1*	*2.5*
Implicit price deflator—GDP at market prices	1.178	1.188	1.197	1.208	1.210	1.208	1.207	1.207	1.207	1.210	1.214	1.218	1.193	1.208	1.212
(2012 = 1.000)	*0.8*	*0.9*	*0.7*	*0.9*	*0.2*	*-0.1*	*-0.1*	*0.0*	*0.1*	*0.2*	*0.3*	*0.3*	*2.9*	*1.3*	*0.4*
Wages and salary per employee ($ 000s)	54.6	55.5	56.8	57.2	57.3	57.2	57.3	57.6	57.9	58.1	58.5	58.8	56.0	57.3	58.3
	1.2	*1.7*	*2.2*	*0.8*	*0.1*	*-0.1*	*0.2*	*0.5*	*0.5*	*0.5*	*0.5*	*0.6*	*4.1*	*2.3*	*1.7*
Primary household income ($ millions)	232,341	235,256	242,425	248,720	249,890	251,061	252,734	254,925	256,921	259,217	261,239	263,382	239,685	252,153	260,190
	1.9	*1.3*	*3.0*	*2.6*	*0.5*	*0.5*	*0.7*	*0.9*	*0.8*	*0.9*	*0.8*	*0.8*	*9.1*	*5.2*	*3.2*
Household disposable income ($ millions)	210,080	211,206	215,909	216,925	215,827	216,553	218,063	219,981	220,758	222,983	224,889	226,886	213,530	217,606	223,879
	1.2	*0.5*	*2.2*	*0.5*	*-0.5*	*0.3*	*0.7*	*0.9*	*0.4*	*1.0*	*0.9*	*0.9*	*2.4*	*1.9*	*2.9*
Household net savings rate (per cent)	7.3	7.8	4.5	4.2	3.3	2.9	3.1	3.3	2.8	2.8	2.6	2.5	6.0	3.1	2.7
Population (000s)	5,164	5,186	5,215	5,250	5,259	5,268	5,276	5,284	5,296	5,307	5,320	5,332	5,204	5,272	5,314
	0.1	*0.4*	*0.6*	*0.7*	*0.2*	*0.2*	*0.2*	*0.2*	*0.2*	*0.2*	*0.2*	*0.2*	*1.0*	*1.3*	*0.8*
Employment (000s)	2,629	2,631	2,669	2,696	2,694	2,685	2,690	2,698	2,704	2,714	2,718	2,723	2,656	2,692	2,715
	1.6	*0.1*	*1.4*	*1.0*	*-0.1*	*-0.3*	*0.2*	*0.3*	*0.2*	*0.4*	*0.2*	*0.2*	*6.6*	*1.3*	*0.9*
Labour force (000s)	2,836	2,825	2,846	2,852	2,850	2,858	2,866	2,872	2,877	2,882	2,887	2,892	2,840	2,862	2,884
	1.4	*-0.4*	*0.8*	*0.2*	*-0.1*	*0.3*	*0.3*	*0.2*	*0.2*	*0.2*	*0.2*	*0.2*	*3.7*	*0.8*	*0.8*
Labour force participation rate (per cent)	65.6	65.2	65.3	65.0	64.8	64.8	64.9	64.8	64.8	64.7	64.7	64.7	65.3	64.8	64.7
Unemployment rate (per cent)	7.3	6.9	6.2	5.5	5.5	6.1	6.1	6.0	6.0	5.8	5.8	5.8	6.5	5.9	5.9
Retail sales ($ millions)	98,731	99,233	98,267	96,315	95,494	95,987	96,084	97,049	97,750	98,331	99,140	99,888	98,136	96,153	98,777
	3.7	*0.5*	*-1.0*	*-2.0*	*-0.9*	*0.5*	*0.1*	*1.0*	*0.7*	*0.6*	*0.8*	*0.8*	*12.1*	*-2.0*	*2.7*
Housing starts (units, 000s)	52,902	49,795	45,224	42,507	40,000	39,536	36,171	35,850	35,530	35,209	34,889	34,568	47,607	37,889	35,049
	30.7	*-5.9*	*-9.2*	*-6.0*	*-5.9*	*-1.2*	*-8.5*	*-0.9*	*-0.9*	*-0.9*	*-0.9*	*-0.9*	*26.2*	*-20.4*	*-7.5*
Net interprovincial migration (000s)	16.7	17.4	17.7	31.4	15.2	10.4	7.1	5.2	7.9	7.5	7.1	6.8	20.8	9.5	7.3
Net international migration (000s)	52.6	52.2	19.8	18.8	20.9	22.2	24.4	27.3	35.2	38.2	40.3	41.6	35.8	23.7	38.8

Shaded area represents forecast data, *italics indicate percentage change*.
All data are in millions of dollars, seasonally adjusted at annual rates, unless otherwise specified.
For each indicator, the first line is the level and the second line is the percentage change from the previous period.
Sources: The Conference Board of Canada; Statistics Canada; CMHC Housing Time Series Database.

Note: Table above is from the Conference Board of Canada, British Columbia Two-Year Outlook, March 30, 2022.

Appendix A2

Load Forecast Tables

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1. INTRODUCTION

This appendix provides the historical and forecast load data used in Section 3 of the Application. The tables in Section 2 show 10 years of historical data and the before-savings and after-savings forecast for 2022S and 2023F. Section 3 shows the customer forecast data while Section 4 presents the residential UPC data. The tables in Section 5 show the load forecast. Table 5.3 shows the DSM that was deducted from the before-savings forecast to provide the after-savings forecast for 2023F. Tables 6.1 and 6.2 show the variance of the customer accounts and forecasts from 2016 to 2021 when compared to the actuals. Table 6.3 shows the annual growth of customer and load that FBC has experienced since 2016. Tables 6.4 and 6.5 show the Residential UPC and Winter peak variances from forecast from 2019 to 2021. Finally, Table 6.6 shows the system load factor from the years 2016 to 2021 and the forecast load factor for 2022S and 2023F.

The tables in this appendix reflect the acquisition by FBC of the assets and customers of the City of Kelowna electric utility effective March 31, 2013. The acquisition resulted in an increase in direct customers to FBC and a re-distribution of load from wholesale to other rate classes in 2013 and 2014.

2. MONTHLY LOAD FORECAST

Forecast loads are shown:

- before-savings – the load before DSM and includes Normalized loads to December 2021.
- after-savings – the load after DSM and includes Normalized loads to December 2021.

2.1 GROSS LOAD (MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Historical Normalized Actuals													
2012	354,376	315,497	304,411	253,594	237,899	233,308	272,143	275,122	236,457	262,538	313,757	362,555	3,421,657
2013	372,939	327,919	300,296	255,888	249,987	235,093	291,183	274,786	241,239	266,317	303,923	380,406	3,499,975
2014	363,947	304,540	303,886	253,159	241,999	242,933	284,643	269,971	229,496	256,060	300,844	381,603	3,433,082
2015	365,681	319,636	299,774	250,449	249,965	245,501	286,189	276,449	233,713	256,762	300,047	361,987	3,446,152
2016	363,248	311,848	292,351	268,698	248,319	242,786	289,259	280,588	234,770	266,284	332,085	350,062	3,480,297
2017	361,265	295,737	307,586	263,795	249,642	251,284	299,544	288,941	246,701	265,695	326,103	355,527	3,511,820
2018	375,664	309,496	306,028	264,140	273,621	256,591	308,227	297,251	231,377	262,531	302,555	376,342	3,563,824
2019	372,224	288,274	315,330	261,324	268,354	257,653	298,081	293,227	260,757	291,917	313,593	371,724	3,592,459
2020	382,181	332,609	303,499	246,152	239,601	248,354	309,611	303,017	260,523	282,780	333,207	374,349	3,615,884
2021	378,637	338,019	319,817	276,739	257,155	259,320	306,943	294,834	257,175	285,567	334,065	368,654	3,676,926
Before-Savings													
2022S	393,190	335,138	331,640	280,553	267,153	271,396	321,383	310,626	274,609	295,951	337,171	383,507	3,802,317
2023F	396,339	337,950	334,411	282,950	269,568	273,870	324,232	313,473	277,139	298,596	340,037	386,627	3,835,192
After-Savings													
2022S	390,444	332,413	328,981	277,979	264,668	268,968	318,980	308,194	272,123	293,371	334,512	380,802	3,771,436
2023F	390,866	332,540	329,150	277,874	264,687	269,119	319,544	308,746	272,326	293,617	334,927	381,448	3,774,844

2.2 NET LOAD (MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Historical Normalized Actuals													
2012	321,730	286,779	279,732	235,517	222,312	217,842	252,099	254,667	220,598	243,793	286,926	328,517	3,150,511
2013	337,728	297,641	276,667	237,842	233,199	219,696	268,867	254,751	225,078	247,419	279,078	343,897	3,221,865
2014	330,080	277,952	279,588	235,366	226,108	226,460	263,122	250,470	214,691	238,394	276,319	344,675	3,163,224
2015	331,359	290,442	275,968	232,925	232,996	228,619	264,346	255,968	218,317	238,919	275,526	328,297	3,173,683
2016	329,697	284,239	269,871	248,933	231,743	226,433	267,219	259,761	219,415	247,393	302,834	318,710	3,206,245
2017	327,600	270,353	282,545	244,429	232,661	233,596	275,700	266,639	229,612	246,617	297,428	322,834	3,230,015
2018	340,082	282,343	281,627	245,049	253,803	238,507	283,500	274,131	216,479	244,187	277,988	340,643	3,278,339
2019	337,457	264,607	289,706	242,736	249,368	239,550	274,993	270,833	242,244	269,708	287,514	337,042	3,305,758
2020	346,177	302,227	279,953	229,763	224,464	231,690	285,178	279,540	242,297	262,136	304,435	339,684	3,327,545
2021	345,746	308,157	294,337	255,440	238,210	239,708	282,793	272,125	237,826	263,832	306,218	337,045	3,381,436
Before-Savings													
2022S	356,872	305,644	305,096	260,549	249,414	252,595	296,341	287,118	255,390	274,469	309,030	348,812	3,501,329
2023F	359,759	308,223	307,659	262,783	251,668	254,896	298,970	289,745	257,738	276,922	311,668	351,673	3,531,705
After-Savings													
2022S	354,335	303,127	302,639	258,171	247,118	250,352	294,120	284,871	253,093	272,084	306,573	346,312	3,472,795
2023F	354,702	303,224	302,798	258,093	247,157	250,505	294,638	285,378	253,291	272,322	306,947	346,888	3,475,944

2.3 RESIDENTIAL (MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Historical Normalized Actuals													
2012	134,187	105,958	112,447	88,508	81,808	82,946	97,309	91,118	73,417	89,175	117,807	154,029	1,228,709
2013	145,263	115,730	114,637	112,100	90,869	85,319	120,666	100,397	73,591	97,867	124,661	171,845	1,352,945
2014	147,191	120,724	129,852	84,813	80,792	77,673	105,443	102,753	73,260	95,314	119,531	159,107	1,296,452
2015	150,230	122,084	120,304	91,957	76,652	84,441	110,145	97,235	73,384	99,324	125,839	146,556	1,298,150
2016	147,429	121,286	113,080	99,963	91,648	85,702	101,212	96,335	77,431	96,417	129,741	135,335	1,295,580
2017	145,663	112,986	118,857	102,166	94,155	86,021	106,392	95,082	82,012	96,745	129,829	150,584	1,320,492
2018	154,740	121,081	119,975	97,261	100,276	86,146	109,349	100,153	70,342	89,942	112,695	150,638	1,312,598
2019	147,714	98,552	116,377	90,039	91,727	81,739	100,157	94,674	87,612	98,618	112,609	146,320	1,266,137
2020	150,634	126,164	117,219	93,211	89,289	91,128	111,958	103,644	86,533	100,913	126,958	149,181	1,346,832
2021	151,923	132,351	117,698	95,324	88,510	89,335	114,977	114,763	58,293	98,449	123,064	145,645	1,330,331
Before-Savings													
2022S	149,350	118,436	116,520	92,400	89,399	86,970	106,340	99,003	84,580	98,837	120,281	146,323	1,308,438
2023F	149,488	118,545	116,628	92,485	89,481	87,050	106,438	99,094	84,658	98,928	120,392	146,458	1,309,643
After-Savings													
2022S	148,891	117,988	116,106	92,031	89,075	86,679	106,062	98,712	84,257	98,468	119,867	145,876	1,304,011
2023F	148,568	117,647	115,796	91,743	88,830	86,464	105,876	98,507	84,003	98,180	119,551	145,549	1,300,714

2.4 COMMERCIAL (MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Normliazed Actuals													
2012	64,101	63,452	59,292	53,673	54,431	49,553	55,968	62,008	56,661	52,596	57,398	51,423	680,553
2013	65,750	60,623	56,214	57,036	69,494	61,665	67,834	73,941	72,704	67,185	66,229	69,533	788,208
2014	80,917	72,012	69,241	70,566	73,379	72,714	75,404	74,677	66,669	60,028	65,444	82,026	863,078
2015	81,041	74,201	68,933	64,674	71,533	72,581	71,204	71,712	68,657	62,650	66,828	79,463	853,478
2016	82,612	75,915	71,711	71,671	69,996	66,744	76,904	77,981	68,748	70,333	81,859	90,367	904,841
2017	85,017	74,211	77,360	69,012	70,513	72,529	81,817	81,344	72,335	73,835	78,070	78,916	914,960
2018	87,447	74,470	78,245	70,839	73,624	72,175	81,335	82,374	71,079	73,218	76,070	85,202	926,078
2019	86,215	75,958	80,152	69,784	72,863	72,688	80,601	81,248	73,015	75,305	77,661	86,230	931,722
2020	88,558	80,807	76,026	63,736	65,028	67,948	79,777	81,941	74,160	76,659	80,994	86,252	921,886
2021	88,860	79,418	80,125	72,153	73,680	74,618	79,949	69,139	96,038	76,264	81,554	87,844	959,641
Before-Savings													
2022S	91,281	81,781	81,825	71,225	73,270	74,552	85,487	85,537	76,428	79,040	83,178	90,148	973,752
2023F	93,329	83,616	83,662	72,825	74,916	76,228	87,409	87,461	78,147	80,815	85,045	92,172	995,624
After-Savings													
2022S	90,298	80,801	80,856	70,272	72,331	73,624	84,563	84,609	75,489	78,086	82,209	89,168	962,307
2023F	91,368	81,668	81,740	70,935	73,057	74,392	85,584	85,632	76,304	78,952	83,163	90,278	973,073

Note: The commercial class is normalized from 2014 to 2020 since weather correlation appeared in the data at that time, all numbers before 2014 are actuals.

2.5 WHOLESALE (MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Historical Normalized Actuals													
2012	96,036	85,333	81,119	66,560	58,307	59,084	69,719	70,177	60,311	72,646	82,146	97,532	898,971
2013	103,661	88,423	80,309	42,225	37,653	34,630	44,414	42,889	38,531	44,175	51,637	66,656	675,204
2014	64,115	50,647	51,900	41,917	35,985	34,959	43,081	42,482	38,972	41,116	53,678	68,270	567,123
2015	65,841	58,564	51,584	41,088	41,147	36,029	45,222	43,897	37,441	42,668	51,945	65,059	580,485
2016	64,687	55,006	49,218	43,812	36,262	35,106	48,506	43,480	37,096	43,408	59,685	58,167	574,434
2017	61,637	51,026	51,573	40,753	35,692	35,965	47,044	49,971	39,411	42,639	56,771	61,621	574,101
2018	65,721	51,837	50,293	43,769	41,467	33,766	45,024	47,275	36,478	47,576	54,103	67,407	584,715
2019	61,944	48,097	50,091	42,390	39,513	36,881	47,393	44,924	37,351	44,052	49,804	63,534	565,972
2020	64,233	56,219	48,768	39,333	33,066	35,088	44,642	44,913	39,548	45,075	55,660	62,943	569,488
2021	63,822	56,888	51,016	42,771	35,118	32,874	43,009	44,315	36,150	44,201	57,331	58,330	565,827
Before-Savings													
2022S	64,807	54,940	51,149	42,542	37,128	36,250	46,538	46,193	38,848	45,583	55,516	63,082	582,577
2023F	65,192	55,265	51,454	42,796	37,362	36,483	46,834	46,485	39,088	45,858	55,846	63,460	586,125
After-Savings													
2022S	64,456	54,593	50,813	42,220	36,821	35,954	46,246	45,897	38,540	45,261	55,180	62,735	578,717
2023F	64,492	54,573	50,785	42,156	36,752	35,895	46,253	45,897	38,481	45,223	55,184	62,779	578,470

2.6 INDUSTRIAL (MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Historical Actuals													
2012	24,973	30,356	25,036	25,285	23,707	21,432	22,094	22,115	22,666	22,863	26,328	23,917	290,771
2013	19,966	30,774	23,744	24,489	31,517	33,006	29,815	29,726	31,598	32,105	32,500	33,084	352,325
2014	35,943	32,746	26,411	34,532	30,112	32,770	29,719	22,362	30,032	38,104	35,138	33,043	380,912
2015	32,138	33,574	32,797	31,186	36,574	26,261	27,971	34,078	32,395	29,853	27,852	34,997	379,676
2016	32,901	29,835	33,180	28,953	27,588	31,785	31,632	32,805	30,120	33,350	28,559	32,687	373,396
2017	33,109	30,227	32,593	30,117	27,928	31,621	29,477	29,518	28,665	28,831	30,770	29,734	362,590
2018	30,089	33,113	31,062	30,455	32,718	39,030	38,264	35,307	33,245	30,034	33,591	35,836	402,744
2019	40,014	40,563	41,563	37,886	39,198	40,876	38,967	41,784	39,929	49,045	45,695	39,390	494,911
2020	41,115	37,485	36,324	30,596	32,632	32,899	39,933	39,350	35,590	36,265	39,250	39,794	441,233
2021	39,629	38,120	44,021	42,125	34,088	34,473	33,956	35,536	42,333	41,558	42,792	43,684	472,315
Before-Savings													
2022S	49,922	49,087	54,123	51,558	43,838	48,000	48,703	47,580	50,264	47,957	48,513	47,775	587,321
2023F	50,238	49,396	54,438	51,852	44,129	48,312	49,017	47,901	50,575	48,269	48,844	48,099	591,072
After-Savings													
2022S	49,195	48,360	53,402	50,840	43,130	47,296	48,007	46,881	49,566	47,241	47,795	47,067	578,779
2023F	48,797	47,968	53,031	50,464	42,773	46,975	47,708	46,597	49,287	46,956	47,539	46,827	574,920

2.7 LIGHTING (MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Historical Actuals													
2012	1,618	1,031	1,232	601	1,666	601	1,661	1,137	611	1,127	1,137	1,064	13,487
2013	1,532	863	1,003	1,112	1,186	1,101	1,151	1,069	1,135	1,132	1,080	1,114	13,479
2014	1,282	1,273	1,251	1,310	1,327	1,331	1,329	1,374	1,257	1,255	1,260	1,382	15,633
2015	1,319	1,339	1,261	1,321	1,372	1,382	1,299	1,347	1,248	1,349	1,295	1,359	15,891
2016	1,245	1,363	1,341	1,362	1,361	1,347	1,404	1,381	1,294	1,191	1,251	1,388	15,930
2017	1,394	1,233	1,390	1,286	1,339	1,301	1,383	1,382	1,289	1,335	1,270	1,330	15,932
2018	1,385	1,178	1,291	1,307	1,198	1,118	1,068	998	988	952	848	894	13,225
2019	907	808	873	943	965	937	917	949	955	947	909	928	11,039
2020	929	892	955	900	914	874	932	949	878	907	863	852	10,846
2021	838	774	836	795	858	787	802	805	770	851	776	791	9,682
Before-Savings													
2022S	820	759	817	809	839	797	813	829	798	830	782	789	9,682
2023F	820	759	817	809	839	797	813	829	798	830	782	789	9,682
After-Savings													
2022S	804	743	802	795	826	784	801	816	785	816	766	773	9,511
2023F	788	728	788	783	816	775	792	808	777	807	758	765	9,385

2.8 IRRIGATION (MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Historical Normalized Actuals													
2012	816	650	606	890	2,393	4,226	5,348	8,113	6,933	5,385	2,109	552	38,019
2013	1,557	1,228	759	880	2,480	3,974	4,986	6,729	7,519	4,955	2,970	1,666	39,704
2014	633	549	932	2,227	4,512	7,013	8,146	6,822	4,501	2,578	1,267	847	40,025
2015	790	680	1,089	2,698	5,718	7,925	8,506	7,700	5,192	3,074	1,768	863	46,003
2016	822	834	1,341	3,172	4,888	5,748	7,561	7,778	4,724	2,694	1,739	765	42,065
2017	780	670	772	1,096	3,035	6,160	9,587	9,343	5,898	3,231	719	649	41,939
2018	700	662	761	1,419	4,521	6,271	8,461	8,024	4,348	2,465	681	666	38,979
2019	663	630	650	1,694	5,103	6,429	6,958	7,254	3,381	1,741	835	640	35,978
2020	708	660	662	1,987	3,535	3,752	7,936	8,743	5,588	2,317	709	662	37,260
2021	674	606	641	2,272	5,957	7,621	10,099	7,568	4,242	2,508	701	751	43,640
Before-Savings													
2022S	692	642	661	2,015	4,940	6,025	8,459	7,976	4,472	2,222	760	695	39,559
2023F	692	642	661	2,015	4,940	6,025	8,459	7,976	4,472	2,222	760	695	39,559
After-Savings													
2022S	691	641	660	2,013	4,935	6,015	8,442	7,956	4,456	2,213	756	693	39,471
2023F	690	640	659	2,011	4,930	6,004	8,425	7,936	4,440	2,204	752	691	39,382

2.9 SYSTEM PEAK (MW)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Winter	Summer
Historical Normalized Actuals														
2012	702	675	560	523	493	418	589	540	453	501	624	723	723	589
2013	720	631	549	493	515	442	600	565	523	502	598	698	698	600
2014	651	580	562	469	403	482	620	605	412	467	572	645	693	620
2015	693	679	568	488	501	523	611	587	437	514	669	631	685	611
2016	685	683	569	540	490	582	587	593	443	480	613	724	755	593
2017	755	673	595	510	597	505	600	605	561	515	594	648	714	605
2018	714	648	583	516	602	533	630	631	429	459	609	659	682	631
2019	678	682	651	514	568	502	626	639	538	562	622	701	732	639
2020	732	680	609	500	482	515	666	665	551	549	631	667	731	666
2021	711	731	555	495	488	653	597	635	486	509	628	675	685	653
Before-Savings														
2022S	725	687	608	516	488	588	658	661	502	537	645	722	783	679
2023F	732	693	614	521	493	593	664	667	506	542	650	728	788	685
After-Savings														
2022S	725	686	608	515	488	587	657	660	501	536	644	721	782	678
2023F	730	692	612	519	491	592	662	665	505	540	649	727	786	684

Note: The peaks shown in the table above are seasonal peaks. The seasonal winter peak is based on November and December of the current year and January and February of the following year. The seasonal summer peak is based on June, July and August of the current year and includes the June 2021 Heat Dome.

3. CUSTOMER FORECAST

3.1 CUSTOMERS

Customer Count	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022S	2023F
Residential	99,228	111,862	113,431	114,166	115,772	117,748	120,291	122,465	124,966	126,678	129,336	132,015
Commercial	11,811	13,662	14,363	14,976	15,073	15,398	15,678	15,956	16,165	16,594	16,995	17,496
Wholesale	7	6	6	6	6	6	6	6	6	6	6	6
Industrial	39	47	49	50	50	50	52	51	43	42	42	42
Lighting	1,739	1,644	1,620	1,590	1,559	1,511	1,482	1,467	1,443	1,407	1,379	1,349
Irrigation	1,091	1,097	1,103	1,095	1,090	1,080	1,078	1,082	1,091	1,103	1,103	1,103
Total Direct	113,915	128,318	130,572	131,883	133,550	135,793	138,587	141,027	143,714	145,830	148,861	152,011

3.2 CUSTOMER ADDITIONS

Customer Additions	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022S	2023F
Residential	912	12,634	1,569	735	1,606	1,976	2,543	2,174	2,501	1,712	2,658	2,679
Commercial	106	1,851	701	613	97	325	280	278	209	429	401	501
Wholesale	-	(1)	-	-	-	-	-	-	-	-	-	-
Industrial	1	8	2	1	-	-	2	(1)	(8)	(1)	-	-
Lighting	(27)	(95)	(24)	(30)	(31)	(48)	(29)	(15)	(24)	(36)	(28)	(30)
Irrigation	17	6	6	(8)	(5)	(10)	(2)	4	9	12	-	-
Total Direct	1,009	14,403	2,254	1,311	1,667	2,243	2,794	2,440	2,687	2,116	3,031	3,150

4. NORMALIZED AFTER-SAVINGS USE PER CUSTOMER (UPC)

MWh/Customer	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022S	2023F
Residential	12.41	12.48	11.51	11.41	11.27	11.31	11.03	10.43	10.89	10.58	10.19	9.95

5. LOAD

5.1 NORMALIZED AFTER-SAVINGS LOAD

Energy (GWh)	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022S	2023F
Residential	1,229	1,353	1,296	1,298	1,296	1,320	1,313	1,266	1,347	1,330	1,304	1,301
Commercial	681	788	863	853	905	915	926	932	922	960	962	973
Wholesale	899	675	567	580	574	574	585	566	569	566	579	578
Industrial	291	352	381	380	373	363	403	495	441	472	579	575
Lighting	13	13	16	16	16	16	13	11	11	10	10	9
Irrigation	38	40	40	46	42	42	39	36	37	44	39	39
Net	3,151	3,222	3,163	3,174	3,206	3,230	3,278	3,306	3,328	3,381	3,473	3,476
Losses & Company Use	271	278	270	272	274	282	285	287	288	295	299	299
Gross	3,422	3,500	3,433	3,446	3,480	3,512	3,564	3,592	3,616	3,677	3,771	3,775
System Peak (MW)												
Winter Peak	723	698	693	685	755	714	682	732	731	685	782	786
Summer Peak	589	600	620	611	593	605	631	639	666	653	678	684

5.2 NORMALIZED AFTER-SAVINGS WHOLESALE LOAD

Wholesale (GWh)	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2021S	2022F
BCH Lardeau	6	6	6	6	6	8	8	7	6	6	7	7
BCH Kingsgate	5	5	5	5	5	5	5	5	5	4	5	5
City of Grand Forks	41	41	39	41	41	39	46	37	38	36	36	36
City of Nelson	80	83	81	83	80	86	88	84	82	86	79	78
City of Penticton	341	348	342	348	345	338	340	338	340	337	351	351
District of Summerland	95	98	94	97	98	98	99	95	99	97	101	101
City of Kelowna	332	94	-	-	-	-	-	-	-	-	-	-
Total	899	675	567	580	574	574	585	566	569	566	579	578

5.3 DSM (GWH) WITHOUT LOSSES

Energy (GWh)	2017	2018	2019	2020	2021	2022S	2023F
Demand Side Management	(28)	(31)	(26)	(26)	(30)	(28)	(56)

6. VARIANCES TO FORECAST

6.1 CUSTOMER COUNT VARIANCE

Customer Count	2016	2017	2018	2019	2020	2021
Actual						
Residential	115,772	117,748	120,291	122,465	124,966	126,678
Commercial	15,073	15,398	15,678	15,956	16,165	16,594
Wholesale	6	6	6	6	6	6
Industrial	50	50	52	51	43	42
Lighting	1,559	1,511	1,482	1,467	1,443	1,407
Irrigation	1,090	1,080	1,078	1,082	1,091	1,103
Total	133,550	135,793	138,587	141,027	143,714	145,830
Forecast						
Residential	115,758	116,031	117,774	120,405	124,076	124,603
Commercial	15,042	15,813	16,122	16,405	16,220	16,579
Wholesale	6	6	6	6	6	6
Industrial	49	50	50	51	57	59
Lighting	1,620	1,590	1,559	1,511	1,425	1,393
Irrigation	1,103	1,095	1,090	1,080	1,082	1,082
Total	133,578	134,585	136,602	139,459	142,865	143,721
Variance (customers)						
Residential	14	1,717	2,517	2,060	890	2,075
Commercial	31	(415)	(444)	(449)	(55)	15
Wholesale	0	0	0	0	0	0
Industrial	1	0	2	0	(14)	(17)
Lighting	(61)	(79)	(77)	(44)	18	14
Irrigation	(13)	(15)	(12)	2	9	21
Total	(28)	1,208	1,986	1,569	849	2,109
Variance (%)						
Residential	0.0%	1.5%	2.1%	1.7%	0.7%	1.6%
Commercial	0.2%	-2.7%	-2.8%	-2.8%	-0.3%	0.1%
Wholesale	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Industrial	2.0%	0.0%	3.8%	0.0%	-32.6%	-40.5%
Lighting	-3.9%	-5.2%	-5.2%	-3.0%	1.3%	1.0%
Irrigation	-1.2%	-1.4%	-1.1%	0.2%	0.8%	1.9%
Total	0.0%	0.9%	1.4%	1.1%	0.6%	1.4%

6.2 LOAD VARIANCE, NORMALIZED ACTUAL TO FORECAST

Energy (GWh)	2016	2017	2018	2019	2020	2021
Normalized						
Residential	1,296	1,320	1,313	1,266	1,347	1,330
Commercial	905	915	926	932	922	960
Wholesale	574	574	585	566	569	566
Industrial	373	363	403	495	441	472
Lighting	16	16	13	11	11	10
Irrigation	42	42	39	36	37	44
Net	3,206	3,230	3,278	3,306	3,328	3,381
Gross	3,480	3,512	3,564	3,592	3,616	3,677
Forecast						
Residential	1,367	1,353	1,280	1,349	1,326	1,255
Commercial	871	879	912	935	902	952
Wholesale	579	587	586	594	567	584
Industrial	393	407	379	385	453	537
Lighting	13	14	15	13	11	10
Irrigation	39	40	41	42	35	36
Net	3,262	3,282	3,213	3,319	3,294	3,374
Gross	3,540	3,559	3,485	3,602	3,602	3,664
Variance (GWh)						
Residential	(71)	(33)	33	(83)	21	75
Commercial	34	36	14	(3)	20	7
Wholesale	(5)	(13)	(1)	(28)	2	(18)
Industrial	(20)	(44)	24	110	(12)	(64)
Lighting	3	1	(2)	(2)	0	(0)
Irrigation	3	2	(2)	(6)	2	8
Net	(56)	(52)	65	(13)	34	8
Gross	(59)	(47)	79	(10)	14	13
Variance (%)						
Residential	-5.5%	-2.5%	2.5%	-6.6%	1.6%	5.6%
Commercial	3.8%	3.9%	1.5%	-0.4%	2.2%	0.8%
Wholesale	-0.8%	-2.3%	-0.2%	-5.0%	0.4%	-3.1%
Industrial	-5.3%	-12.3%	5.9%	22.2%	-2.7%	-13.6%
Lighting	16.3%	9.4%	-13.4%	-17.8%	2.1%	-2.8%
Irrigation	7.7%	3.9%	-5.2%	-16.7%	5.3%	17.9%
Net	-1.7%	-1.6%	2.0%	-0.4%	1.0%	0.2%
Gross	-1.7%	-1.3%	2.2%	-0.3%	0.4%	0.4%

6.3 NORMALIZED AFTER-SAVINGS ANNUAL PERCENT GROWTH

Energy (GWh)	2016	2017	2018	2019	2020	2021	2022S	2023F
Residential	1,296	1,320	1,313	1,266	1,347	1,330	1,304	1,301
Commercial	905	915	926	932	922	960	962	973
Wholesale	574	574	585	566	569	566	579	578
Industrial	373	363	403	495	441	472	579	575
Lighting	16	16	13	11	11	10	10	9
Irrigation	42	42	39	36	37	44	39	39
Net	3,206	3,230	3,278	3,306	3,328	3,381	3,473	3,476
Losses & Company Use	274	282	285	287	288	295	299	299
Gross	3,480	3,512	3,564	3,592	3,616	3,677	3,771	3,775
System Peak								
Winter Peak (MW)	755	714	682	732	731	685	782	786
Summer Peak (MW)	593	605	631	639	666	653	678	684

Growth Year over Year	2016	2017	2018	2019	2020	2021	2022S	2023F
Residential	0%	2%	-1%	-4%	6%	-1%	-2%	0%
Commercial	6%	1%	1%	1%	-1%	4%	0%	1%
Wholesale	-1%	0%	2%	-3%	1%	-1%	2%	0%
Industrial	-2%	-3%	11%	23%	-11%	7%	23%	-1%
Lighting	0%	0%	-17%	-17%	-2%	-11%	-2%	-1%
Irrigation	-9%	0%	-7%	-8%	4%	17%	-10%	0%
Net	1%	1%	1%	1%	1%	2%	3%	0%
Losses & Company Use	1%	3%	1%	0%	1%	2%	1%	0%
Gross	1%	1%	1%	1%	1%	2%	3%	0%
System Peak								
Winter Peak (MW)	10%	-5%	-4%	7%	0%	-6%	14%	0%
Summer Peak (MW)	-3%	2%	4%	1%	4%	-2%	4%	1%

Customer Count	2016	2017	2018	2019	2020	2021	2022S	2023F
Residential	115,772	117,748	120,291	122,465	124,966	126,678	129,336	132,015
Commercial	15,073	15,398	15,678	15,956	16,165	16,594	16,995	17,496
Wholesale	6	6	6	6	6	6	6	6
Industrial	50	50	52	51	43	42	42	42
Lighting	1,559	1,511	1,482	1,467	1,443	1,407	1,103	1,103
Irrigation	1,090	1,080	1,078	1,082	1,091	1,103	1,379	1,349
Total Direct	133,550	135,793	138,587	141,027	143,714	145,830	148,861	152,011

Growth Year over Year	2016	2017	2018	2019	2020	2021	2022S	2023F
Residential	1%	2%	2%	2%	2%	1%	2%	2%
Commercial	1%	2%	2%	2%	1%	3%	2%	3%
Wholesale	0%	0%	0%	0%	0%	0%	0%	0%
Industrial	0%	0%	4%	-2%	-16%	-2%	0%	0%
Lighting	-2%	-3%	-2%	-1%	-2%	-2%	-22%	0%
Irrigation	0%	-1%	0%	0%	1%	1%	25%	-2%
Total Direct	1%	2%	2%	2%	2%	1%	2%	2%

6.4 RESIDENTIAL UPC, NORMALIZED ACTUAL TO FORECAST

Residential UPC (MWh)	2019	2020	2021
After- Savings Normalized Actual UPC	10.43	10.89	10.58
Forecast	11.27	10.75	10.10
Variance	(0.84)	0.13	0.49
Variance (%)	-8.0%	1.2%	4.6%

6.5 WINTER PEAK , ACTUAL TO FORECAST

Winter Peak (MW)	2019	2020	2021
After- Savings Actual Peak	732	725	777
Forecast	764	737	748
Variance	(32)	(12)	29
Variance (%)	-4%	-2%	4%

Note: The peaks reflected in this table are the actual seasonal peaks are not normalized.

6.6 SYSTEM LOAD FACTOR

The following table shows annual after-savings gross load, peak load and load factor. The annual load factor is calculated as annual load ÷ peak hourly load x number of hours in a year (8,760).

Year	Energy (MWh)	Peak (MW)	Load Factor
2016	3,480,297	755	0.53
2017	3,511,820	714	0.56
2018	3,563,824	682	0.60
2019	3,592,459	732	0.56
2020	3,615,884	731	0.56
2021	3,676,926	685	0.61
2022S	3,771,436	782	0.55
2023F	3,774,844	786	0.55

Note: The peaks in this table represent annual peaks meaning they happened in the calendar year and are not the seasonal peaks.

Appendix A3

Load Forecast Methods

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1. LOAD FORECAST METHODS

This appendix describes FBC's load forecast methods on which the forecast in Section 3 of the Application is based.

In the figures provided in this appendix, the following three time frames are shown:

- Actual Years: Actual years are those for which actual data exists for the full calendar year[1]. For the 2023 Annual Review the latest calendar year for which full actual data exists is the 2021 calendar year.
- Seed Year: The Seed Year is the year prior to the first forecast year. The Seed Year is forecast based on the latest years of actual data available, and will be different than the original forecast for that year in the previous filing. For example, for this Application the Seed Year is 2022 (2022S) and the Seed Year forecast is based on the latest actual years, including 2021. As such, the 2022 Seed Year forecast in this Application will differ from the 2022 Forecast presented in the Annual Review for 2022 Rates, for which 2021 actual data was not available.
- Forecast Year(s): This is the year or years for which the forecast is being developed. This can be one year (in the case of the Annual Review) or a range of two or more years depending on the filing. In this Application, 2023 is the Forecast Year (2023F).

1.1 *WEATHER NORMALIZATION*

Electricity consumption is impacted by weather, particularly by temperature. For example, load requirements in an extremely cold winter month can be significantly higher than requirements in normal weather conditions in the same month, due to additional heating loads. As the load forecast is made under an assumption of normal weather, it is necessary to remove those extreme weather effects from the historical data. This is the first step in forecasting.

Statistical tests were made to check whether the residential, wholesale, commercial and irrigation loads were sensitive to temperature due to heating and cooling demands and whether the irrigation load was sensitive to the amount of precipitation[2]. The results from the regression for these four rate classes are shown below. The regressions result in high R^2 values for all seasons for the residential, wholesale and commercial[3] load classes; therefore these classes are normalized. The irrigation class shows a low R^2 value for the winter, summer and fall seasons; therefore, this class was not normalized.

[1] FBC's load forecast is developed using only full years of historical data. FBC requires the full year of load data in order to validate it, including the review of and potential adjustments to unbilled energy. For this reason partial year data is not used in forecasting.
[2] Industrial and lighting loads are typically insensitive to the weather.
[3] The commercial class data is normalized from 2014 to 2021 since a strong correlation was present in those years. All commercial data prior to 2014 is actual because it did not show a correlation to weather at that time.

Table A3-1: Residential Regression Table

Residential	Winter	Spring	Summer	Fall
Intercept	39,370	66,140	70,359	64,926
Slope HDD	172	109	-	92
Slope CDD	-	-	245	-
Adjusted R^2	0.72	0.76	0.84	0.77

Table A3-2: Wholesale Regression Table

Wholesale	Winter	Spring	Summer	Fall
Intercept	61,401	57,123	58,803	60,135
Slope HDD	58	47	-	36
Slope CDD	-	-	90	-
Adjusted R^2	0.91	0.92	0.85	0.91

Table A3-3: Commercial Regression Table

Commercial	Winter	Spring	Summer	Fall
Intercept	48,156	51,092	49,674	54,643
Slope HDD	24	16	-	(0)
Slope CDD	-	-	78	-
Adjusted R^2	0.58	0.54	0.68	0.53

Table A3-4: Irrigation Regression Table

Irrigation	Winter	Spring	Summer	Fall
Intercept	1,634	5,218	5,079	6,034
Slope HDD	(1)	(11)	-	(10)
Slope CDD	-	-	23	-
Adjusted R^2	0.04	0.76	0.45	0.43

Steps for weather (temperature) normalization are as follows:

1. Calculate monthly Heating Degree Days (HDD)[4] and Cooling Degree Days (CDD)[5] for the Penticton weather station.
2. Calculate 10-year HDD and CDD averages for each month of the year. These are used as the parameters of normal weather.
3. For each of the residential, wholesale and commercial classes, regress load on HDD or CDD on a seasonal basis. Four seasons were defined: winter (November to February), spring (March to May), summer (June to August) and fall (September to October). Thus all monthly load and degree day data for each season is used and four separate

[4] Heating degree-days for a given day are the number of Celsius degrees that the mean temperature is below 18 Celsius degrees.
[5] Cooling degree-days for a given day are the number of Celsius degrees that the mean temperature is above 18 Celsius degrees.

regressions are calculated for each class. The City of Kelowna (CoK) Event variables were included in the regressions to recognize the integration of the CoK in 2013 into the FBC direct customer base.

4. To normalize a month, e.g. February 2021:

   (a) obtain the month's HDD (or CDD) information from Environment Canada;

   (b) calculate the deviation from the 10-year average (2012-2021) HDD (CDD) as found in Step 2;

   (c) apply the regression slope obtained in Step 3 to this deviation to come up with a normalization adder; and

   (d) add the normalization adder to the month's load (residential, commerical or wholesale).

The general equation to normalize load requirements in month t is shown below.

$$Normalized\ Load_t = Load_t - HDD\ Slope_t \times (HDD_t - Normal\ HDD_t)$$

$$where\ HDD\ is\ Heating\ Degree\ Days\ and\ t = Spring, Fall\ and\ Winter$$

And

$$Normalized\ Load_t = Load_t - CDD\ Slope_t \times (CDD_t - Normal\ CDD_t)$$

$$where\ CDD\ is\ Cooling\ Degree\ Days\ and\ t = Summer$$

1.2 *LOAD FORECAST*

FBC forecasts energy requirements by customer class based on weather normalized historical loads. These are referred to as the "before-savings[6]" loads. DSM savings that are incremental to those embedded in historical loads (up to and including 2021) are also forecast for each customer class and subtracted from the before-savings loads to arrive at the "after-savings" loads. This section discusses the before-savings forecast load requirements for each of FBC's load classes.

1.2.1 Residential

The formula to forecast the expected before-savings residential load in year *t* is:

$$Before\ Savings\ Load_t = UPC_t \times Average\ Customer\ Count_t$$

where UPC (use per customer in MWh per customer per year) is before-savings.

[6] The term "before-savings" is used in the remainder of this section and refers to "before incremental savings after 2021".

The before-savings UPC was based on a 10-year historic trend of annual UPC values from 2012 to 2021. FBC reviews the forecast methods on an annual basis. As FBC found that there was a strong correlation, it therefore applied a 10-year trend.

Table A3-5: Results of UPC Trend Analysis

Regression	UPC
Start Year	2012
End Year	2021
R^2	0.84
Adjusted R^2	0.82
df	9
Intercept	414
Slope UPC	-0.20

Next, average customer count in year *t* is calculated as:

$$Average\ Customer\ Count_t = \frac{(Year\ End\ Count_t + Year\ End\ Count_{t-1})}{2}$$

The year-end customer count was based on the least squares regression model below.

$$Year\ End\ Customer\ Count_t = b_0 + b_1 \times Population_t$$

$Population_t$ is the population data supplied by BC Stats for the Company's direct service area.

Table A3-6: Results of Residential Regression

Regression	Residential
Start Year	2019
End Year	2021
R^2	1.00
Adjusted R^2	0.99
df	2
Intercept	(118,476)
Slope Population	0.88

The residential class represented 39.3 percent of the net load in 2021.

1.2.2 Commercial

The expected before-savings commercial load in year *t* is forecast based on the provincial GDP supplied by the CBOC. The relationship was estimated from the following equation.

$$Before\ Savings\ Load_t = (b_0 + b_1 \times GDP_t + b_2 \times CoK\ Event_t) + FBC\ EV\ DC\ Fast\ Chargers$$

The CoK_t is a binary variable for the City of Kelowna integration event in 2013. Coefficients b0, b1 and b2 are obtained from an ordinary least squares (OLS) regression analysis on the 2007 to

2021 data. The FBC EV DCFCs are Electric Vehicle Direct Current Fast Chargers serviced by FBC which are added to the forecast. The commercial class represented 28.4 percent of the net load in 2021.

Table A3-7: Results of Commercial Regression

Regression	Commercial
Start Year	2007
End Year	2021
R^2	0.99
Adjusted R^2	0.99
df	14
Intercept	123,607
Slope GDP	3
Slope CoK Event	132,847

1.2.3 Wholesale

The Company forecasts the wholesale load based on load surveys from the wholesale customers. For this forecast, FBC received surveys from all the wholesale customers except one. This customer was contacted multiple times but did not respond. Since there was no response, FBC kept their load at 2021 levels. FBC then summed the wholesale customers' forecasts to calculate the before-savings wholesale load forecast. This approach recognizes that in the near to medium term, the wholesale customers themselves are best able to forecast their load growth based on their knowledge of their customer mix, load behaviors, development projects with associated load requirements, etc. The wholesale class represented 16.7 percent of the net load in 2021.

1.2.4 Industrial

The before-savings industrial load is the sum of forecasts supplied by those individual customers who responded to the load survey and, for customers who did not respond, escalation of the customer's load in the preceding year by the CBOC forecast GDP growth rates for the industrial sector the customer is in. 81 percent of FBC's industrial customers responded to the surveys, accounting for 90 percent of 2021 load.

FBC assumes no new industrial customers in the current forecast unless there is a confirmed commitment from an industrial customer. FBC works with key account managers to identify new customers and existing customers with expansion plans that have commited contracts that are being added to the system. The key account managers work with the new customers directly and relay the load requirements to the forecasting group. The industrial class represented 14.0 percent of the net load in 2021.

1.2.5 Irrigation

The before-savings irrigation load forecast uses a five-year average so that the extreme weather events such as those that occurred in 2021 are included in the forecast but do not overly influence it. The irrigation class represented 1.3 percent of the net load in 2021.

1.2.6 Lighting

The before-savings lighting load uses the 2021 actuals due to the variability in the load primarily due to streetlight LED replacement programs which reduced the loads from 2018 to 2021. The lighting class represented 0.3 percent of the net load in 2021.

1.2.7 Demand Side Mangment (DSM) Savings

FBC forecasts load reductions resulting from its DSM programs.

The forecast of DSM savings is consistent with the Company's approved 2019-2022 DSM Plan. DSM measures are grouped into applicable programs that are then added to produce the three primary sector (residential, commercial & industrial) annual plan savings targets. Finally, the annual sector targets beginning with the Seed Year are converted into a cumulative time series, and disaggregated into the customer rate classes and commensurate system loss reductions.

1.3 *PEAK DEMAND FORECAST*

The peak demand forecast is produced by taking the 10-year average (2012-2021) of historical peak data. The historical peak data is escalated by the gross load growth rate before it is averaged to account for the growth of demand on the FBC system. Self-generating customers are removed from the historical load data since the underlying trends that impact other loads do not apply. Seasonal peaks were used for both the winter and the summer. The 12 monthly peaks, as well as the seasonal peaks, were then escalated by the annual load growth rates in the forecast period to produce forecast monthly peaks. The winter peak and the summer peak are assumed to replace monthly peaks in December and July, respectively.

The after DSM peak forecast was calculated by subtracting DSM capacity savings forecast from the before DSM peak forecast for each month in each year.

Appendix B
PRIOR YEAR DIRECTIVES

No.	Decision Page No.	Directive No.	Reference	Description / Details	Status	Section in this Application
G-8-17 – FBC ANNUAL REVIEW FOR 2017 RATES						
1.	21	6	Upper Bonnington Old Units Refurbishment Project	The Panel directs FBC to report in each of its annual review applications during the remainder of the PBR term the following information on the UBO Refurbishment project: • The status of both the UBO Refurbishment project as a whole and of the individual units, including a comparison of the project timeline provided in the current Applicaton to any updated project timeline as at the time of filing each annual review application. • Updated cost estimates and cost descriptions compared to the cost estimates and scope descriptions provided in the current Application, including explanations for any variances/changes to the cost estimates or project scope. • Actual costs incurred to date on the UBO Refurbishment project as a whole and on each individual unit as at the time of filing each annual review application. • Final actual refurbishment costs at the completion of each unit, including a description of the scope of work completed relative to the conditions found and against the cost estimate.	Complete (Final Report filed in this Annual Review)	Appendix B2
G-165-20 AND G-166-20 – FEI AND FBC MULTI-YEAR RATE PLAN FOR 2020 THROUGH 2024						
2.	75	24	General Flow-through Deferral Account	The Panel directs [FBC] to provide a detailed analysis of the individual forecast variances recorded in the Flow-through deferral account in each Annual Review.	Ongoing during the MRP term	Section 12.4.2.1

No.	Decision Page No.	Directive No.	Reference	Description / Details	Status	Section in this Application
3.	87	32	Efficiency Carry-Over Mechanism	Therefore, the Panel determines the following process for the handling of an ECM application: 1. An ECM can be applied for at any time in the last three years of the MRPs, either in advance or following the action or initiative being undertaken. 2. For proposed activities where identifiable savings are expected to extend beyond the term of the MRP, FortisBC is to file an ECM proposal describing the initiative, its timing, costs and benefits and savings. 3. Parties will have the opportunity to review and comment on the proposal and the BCUC will determine whether to approve the ECM proposal (an Approved ECM Initiative). FortisBC must submit details of continued savings annually under an Approved ECM Initiative as part of the Annual Review process. The net savings will be shared equally between ratepayers and the Utilities will carry forward past the end of the MRP for a maximum period of three years.	No approved ECM initiatives to report on	n/a
4.	99	35	SAIDI and SAIFI major events	The Panel also directs FBC to include a discussion of major events relevant to the SAIDI and SAIFI results in future Annual Review materials.	Ongoing during the MRP term	Section 13
5.	99-100		SQI Informational Indicators	In addition to the SQIs, the Panel approves the following informational indicators for the Utilities: • Customer Satisfaction Index (measures overall customer satisfaction) – FEI and FBC. • Average Speed of Answer (average number of seconds to answer emergency and non-emergency calls) – FEI and FBC. • Generator Forced Outage Rate (percent of time a generating unit is removed from service due to component failure or other events) – FBC only. • Interconnection Utilization (percent of time that an interconnection point was available and providing electrical service to wholesale customers) – FBC only. The Utilities are directed to report on these informational indicators along with the SQIs as part of the Annual Review process.	Ongoing during the MRP term	Section 13

No.	Decision Page No.	Directive No.	Reference	Description / Details	Status	Section in this Application
6.	118	42	System Operations, Integrity and Security Expenditures	The Panel directs FBC to provide the following information related to System Operations, Integrity and Security expenditures in its future revenue requirements applications over the term of the Proposed MRPs: 1. A breakdown and explanation of both annual and cumulative variances between forecast/actual and formula O&M related to System Operations, Integrity and Security expenditures, which quantify the variances attributable to the following areas: • Tree management; • Generation dam safety; • Network operations apprentice program; • Cyber security; • Data analytics; and • Any other significant factors or miscellaneous items. 2. A description of how FBC is prioritizing its System Operations, Integrity and Security expenditures.	Ongoing during the MRP term	Section 6.2.1
7.	131	49	Forecast Capital Expenditures	The Panel directs FortisBC to file an updated forecast of the 2023 to 2024 capital expenditures in the 2023 Annual Review.	Complete	Section 7.2.1
G-42-21 – FBC ANNUAL REVIEW FOR 2020 AND 2021 RATES						
8.	21		COVID-19 Customer Recovery Fund Deferral Account	The Panel approves the following deferral account requests: f. Recording of the COVID-19 incremental costs and related savings from 2020 and 2021 into the previously approved COVID-19 Customer Recovery Fund deferral account, as discussed in Section 12.2.1 of the Application.	Status of COVID-19 exogenous factor treatment provided in this Application	Section 12.2.1
G-374-21 – FBC ANNUAL REVIEW FOR 2022 RATES						
9.	32	7	Wholesale Customer Load Forecast	The Panel directs FBC to provide details of any efforts it has undertaken to improve the accuracy of its forecasts of wholesale customer load in the 2023 Annual Review, including the results of such efforts.	Complete	Section 3.4.3
10.	32	8	EV Charging Updates	The Panel directs FBC to include in future Annual Review filings an update on its EV DCFC charging stations' costs and revenues for the previous fiscal year along with a forecast of costs and revenues for the test period.	Ongoing	Section 6.3.4

Appendix B2

FortisBC Inc.

Upper Bonnington Old Units Refurbishment Project

Final Report

August 2022

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1. PROJECT STATUS

1.1 *PROJECT BACKGROUND*

On January 20, 2017, the British Columbia Utilities Commission (BCUC) approved capital expenditures related to the Upper Bonnington (UBO) Old Units Refurbishment (UBO Refurbishment Project, or the Project) in Order G-8-17. Directive 6 of Order G-8-17 required FBC to file specific information on the Project's updated scope, progress and costs as part of FBC's future annual review applications. Specifically, the BCUC directed FBC to provide the following information about the progress of the Project:

- The status of both the UBO Refurbishment Project as a whole and of the individual units, including a comparison of the Project timeline provided in the [Annual Review for 2017 Rates] Application to any updated Project timeline as at the time of filing each annual review application.
- Updated cost estimates and cost descriptions compared to the cost estimates and scope descriptions provided in the [Annual Review for 2017 Rates] Application, including explanations for any variances/changes to the cost estimates or Project scope.
- Actual costs incurred to date on the UBO Refurbishment Project as a whole and on each individual unit as at the time of filing each annual review application.
- Final actual refurbishment costs at the completion of each unit, including a description of the scope of work completed relative to the conditions found and against the cost estimate.[1]

The UBO Refurbishment Project involved the refurbishment of generating Units 1-4 (the Old Units), which are over 100 years old, in order to extend their lives for an additional 20 years or more. The Project also reduced the safety and environmental risks associated with failures of the aged equipment.

FBC submits the following final report regarding the UBO Refurbishment Project in compliance with Directive 6 of Order G-8-17, including final Project costs (Final Report).

The Project scope of work was completed and closed out in Q4 2021. The four generating units and associated equipment have been put into commercial operation and are performing well.

The Project successfully eliminated or reduced the safety and environmental risks previously associated with operating the plant.

[1] Order G-8-17, Appendix A, page 21.

With regard to the major environmental and safety accomplishments achieved during Project execution, FBC reports that it followed the Environmental Management Plan (EMP) developed in 2017 and the Project had no reportable environmental incidents. Further, the Project accumulated approximately 160 thousand hours without a lost time incident. The majority of the effort on the Project was internal FBC labour, with approximately 19 thousand hours supplied externally. While the COVID-19 pandemic presented challenges during the second half of the Project, the policies and procedures implemented by FBC minimized the risk of infection and Project interruption.

1.2 *WORK COMPLETED SINCE AUGUST 2021 STATUS REPORT*

The following is a brief summary of the work completed since the August 2021 status report filed as Appendix B2 to FBC's Annual Review for 2022 Rates application.

Balance of Plant

The scope of the balance of plant work evolved as the Project progressed and included the following:

Floor modifications – As equipment was removed, the concrete bases were demolished and floor repairs were completed. The plant floor loadings, drawings, demarcation, procedures and site signage updates were completed.

Ventilation access walkway – With the removal of the old switchgear concrete structure, both wall and floor repairs were required. The switchgear concrete structure provided access to plant ventilation systems; with the removal of this concrete, new access walkways and ladders were designed and installed.

Water wheel excitation decommissioning – The water wheel exciters and associated equipment were removed and the intakes were plugged with concrete. The holes through the generator and turbine floors were capped with steel plates. The exciter rheostats and buss were removed and the rheostat room was repurposed for plant equipment storage.

Units 2 and 3

Minor work was completed on Units 2 and 3 which was intentionally delayed until site conditions were preferable in 2021. The work included painting, hazardous materials removal, and the rotor oil leak repair on Unit 3.

Project Close

The Project was closed in Q4 2021 with all equipment and plant transferred back to generation operations.

2. PROJECT SCHEDULE

The following table is updated to show the final completion dates for each unit as well as the balance of plant work.

Table B2-1: Milestone Summary

Milestone	Planned Completion Date	Actual Completion Date	Status
Engineering			
Mechanical Components – Machining and Fabrication Specifications	Q4, 2017	Q4, 2017	Complete
All Units Detailed Engineering	Q1, 2018	Q1, 2018	Complete
Balance of Plant Engineering	Q3, 2020	Q4, 2020	Complete
Procurement of All Major Mechanical/Electrical	Q2, 2020	Q2, 2020	Complete
Construction			
Refurbishment of Unit 3	Q4, 2017	Q4, 2017	Complete
Refurbishment of Unit 4	Q4, 2018	Q4, 2018	Complete
Refurbishment of Unit 1[1]	Q4, 2020	Q4, 2019	Complete
Refurbishment of Unit 2[1]	Q4, 2019	Q4, 2020	Complete
U3 Oil Leak Deficiency Repair	Q1, 2021	Q2, 2021	Complete
Balance of Plant Work	Q2, 2021	Q3, 2021	Complete
Closeout	Q3, 2021	Q4, 2021	Complete

Note:

[1] *Units 1 and 2 construction years were changed from the original schedule to gain efficiencies by removing equipment while operating a live plant.*

2.1 *SCHEDULE SUMMARY*

The rotor oil leak repair work on Unit 3 delayed portions of the Balance of Plant scope of work from Q2 2021 to Q3 2021. The work completed on Units 2 and 3 as outlined above in Section 1.2 was completed in parallel with the Balance of Plant work, and the Project was closed in Q4 2021.

While some of the work was re-scheduled around sequencing concerns and operational constraints, the overall Project duration was as originally planned.

3. PROJECT COSTS

The following table outlines the final Project expenditures.

Table B2-2: Cost Summary

Description	Application/ Control Budget	Final Costs	Variance	Variance
	($000s)			(%)
Unit 4	6,634	8,058	1,424	21%
Unit 3	4,079	6,529	2,450	60%
Unit 2	5,641	6,606	965	17%
Unit 1	8,050	8,287	237	3%
Balance of Plant	860	1,657	797	93%
Subtotal - Construction	25,264	31,137	5,873	23%
Cost of Removal	1,880	1,840	-40	-2%
Project Contingency	3,771	-	-3,771	-
Subtotal - Construction & Removal	30,916	32,997	2,062	7%
AFUDC	867	1,174	307	35%
Total Project Cost	31,783	34,151	2,369	7%

3.1 *PROJECT COST SUMMARY*

The UBO Refurbishment Project was approved with a Class 4 capital cost estimate of $31.783 million in as-spent dollars (including $0.867 million of AFUDC and $1.880 million of removal costs). The Project's cost estimate was at an AACE Class 4 estimate class because of the difficulty in defining the full scope without dismantling the units. Final Project costs (including $1.174 million of AFUDC and $1.840 million of removal costs) are $34.151 million, which is 7 percent or approximately $2.4 million over the control budget. This is well within the typical accuracy range of an AACE Class 4 cost estimate as stated in AACE Recommended Practice 69R-12, Cost Estimate Classification System – As Applied in Engineering, Procurement, and Construction for the Hydropower Industry. As reported in the August 2020 status report, this approximately $2.4 million variance resulted primarily from higher than planned costs to rewind the generators and to refurbish the concealed turbine components.

The cost variances in each Project category are further described below.

Units 1-4 – These variances are explained in the August 2020 status report. In 2021, both Units 2 and 3 painting scope of work that had been delayed was completed. Unit 3 rotor oil leak repair work was completed for a final cost of approximately $0.252 million. These completed scopes are included in the final costs presented in Table B2-2.

Balance of Plant Work – The balance of plant work scope of work was completed with an unfavourable variance of $0.797 million. The Balance of Plant scope of work evolved as the

Project progressed. The installation of new equipment and removal of old equipment within an operating facility presented unanticipated challenges that were not able to be defined during the planning stage. This variance is primarily due to the extra effort required to remove equipment and cabling which was not expected to contain asbestos and the additional civil structural scopes, as well as the floor modifications required to facilitate the new plant equipment.

Cost of Removal – The forecast total for cost of removal is $1.840 million, which represents a favourable variance of $0.040 million.

Contingency – Project contingency has been utilized to offset the variances that were encountered among the different Units.

AFUDC – The total cost for AFUDC is $1.174 million, which represents an unfavourable variance of $0.307 million due to the higher overall Project costs.

3.2 *PROJECT SCOPE CHANGE SUMMARY*

Throughout the Project, FBC made adjustments to address unforeseen challenges and issues which were either not considered or not accessible during the planning stage. These adjustments totalled approximately $2.015 million and were explained in the August 2020 status report.

4. CONCLUSION

The UBO Refurbishment Project is complete and has successfully eliminated or reduced the safety and environmental risks previously associated with operating the plant. The Project maintained schedule and returned the Units to commercial service within the year planned. The final Project costs were well within the typical accuracy range of an AACE Class 4 cost estimate and totalled $34.151 million. This approximately $2.4 million increase was required to complete scope and ensure the units could operate safely for 20 years or more, as originally planned.

Appendix C
PROJECTS AND MARKET REPORT

Market Report: Gas and Electric Transmission and Distribution Cost Impacts 2020-2024

May 2022

The Engagement

FortisBC has engaged Wood Mackenzie Supply Chain Consulting to provide a market report detailing how market factors have impacted and are anticipated to impact North American utility spend between 2020 and 2024. Wood Mackenzie is a global research and consulting firm that provides energy clients with data, analytics, and insights that they rely on for their decision making. Wood Mackenzie Supply Chain Consulting (SCC), formerly PowerAdvocate, utilizes proprietary cloud-based software solutions and bespoke consulting services to enable our clients to leverage data analysis and assist them in navigating an ever-changing marketplace.

Market dynamics over the last two years have created significant inflationary pressures across both materials and services. This market report is specific to two portfolios: electric transmission and distribution (T&D) and gas T&D capital expenditures at Canadian utilities, with labour specific to British Columbia, Canada. In both portfolios, market escalation has been observed since FortisBC's initial Multi-Year Rate Plan (MRP) filing (Quarter 1, 2020 through Quarter 1, 2022). This report also includes a forecast of potential impacts from Quarter 2, 2022 through Quarter 4, 2024.

Qualifications

Wood Mackenzie Supply Chain Intelligence is a suite of cloud-based software solutions that includes a product, Cost Intelligence, which enables our clients to identify market-based risks and opportunities. Cost Intelligence includes thousands of cost models and indices that enable users to understand what a project or item should cost in a dynamic market. Wood Mackenzie Cost Intelligence models were developed to support the energy market. The Wood Mackenzie team starts with industry specifications, technical drawings, supplier 10ks, and other industry information to develop detailed items that tie cost inputs to dynamic market indices. Those indices are then weighted and loaded on the cloud-based platform. The items are combined into categories and sub-categories that reflect clients spend profiles, or specific capital project expenditures.

Methodology

North American Gas and Electric Utility Cost Models

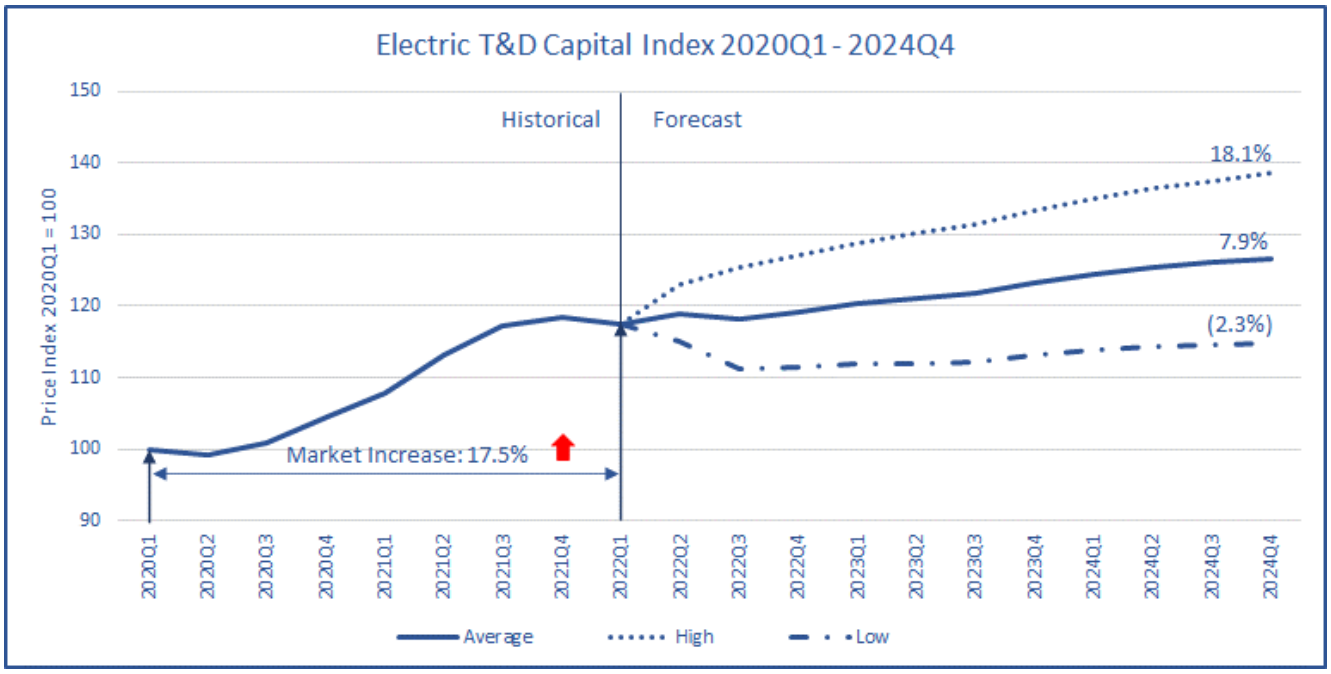
Wood Mackenzie built two customized cost models – Electric Transmission and Distribution and Gas Transmission and Distribution. Each cost model is built from aggregated spend from utilities across North America and over $550M (CAD) in total spend. The models apply indices to spend at an item level and roll up to sub-category, category, and facility level. Each model incorporates over 150 indices tracked monthly by Wood Mackenzie.

Customization for British Columbia Specific Labour Pool

British Columbia (BC) has a unique labour pool and, where appropriate, the models incorporate indices specific to BC, particularly around trade labour and any other labour activities specific to the BC province.

Market Insights

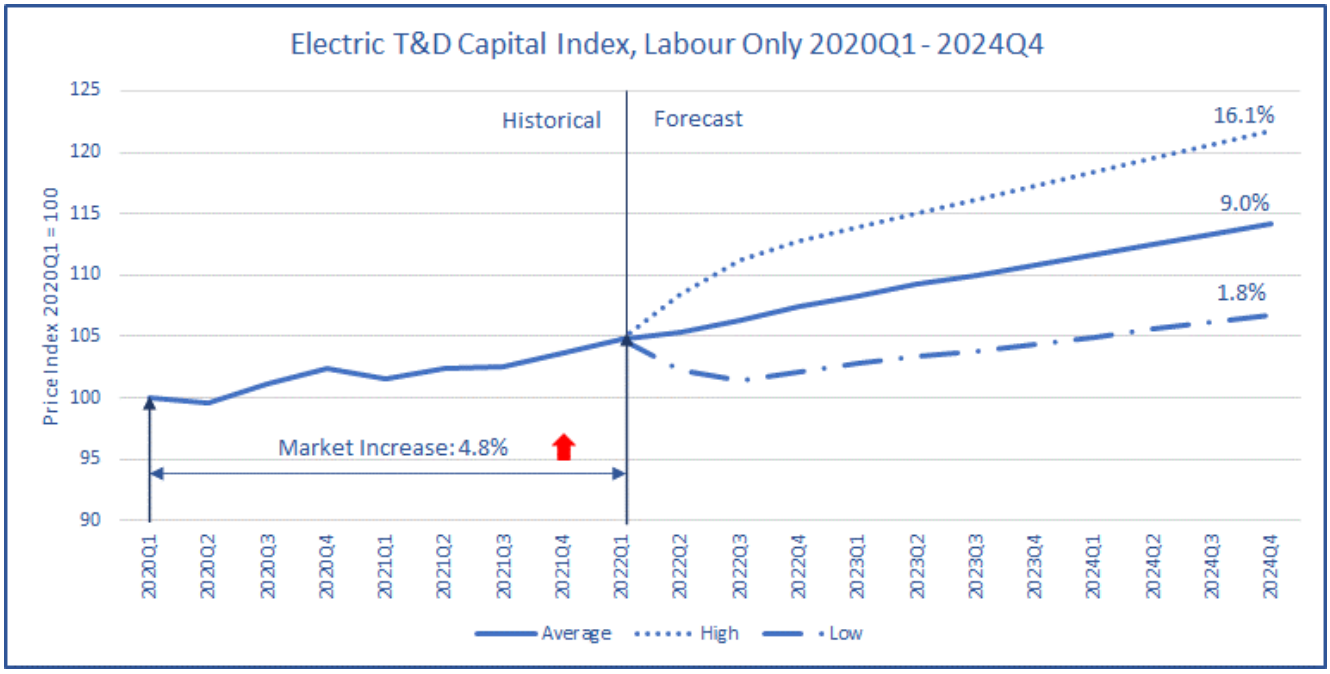
Electric Transmission and Distribution 2020Q1-2024Q4



*This graph includes an aggregate of multiple indices, including both labour and material cost components.
**Forecasted percentage increases or decreases are based on index 2022Q1 = 100

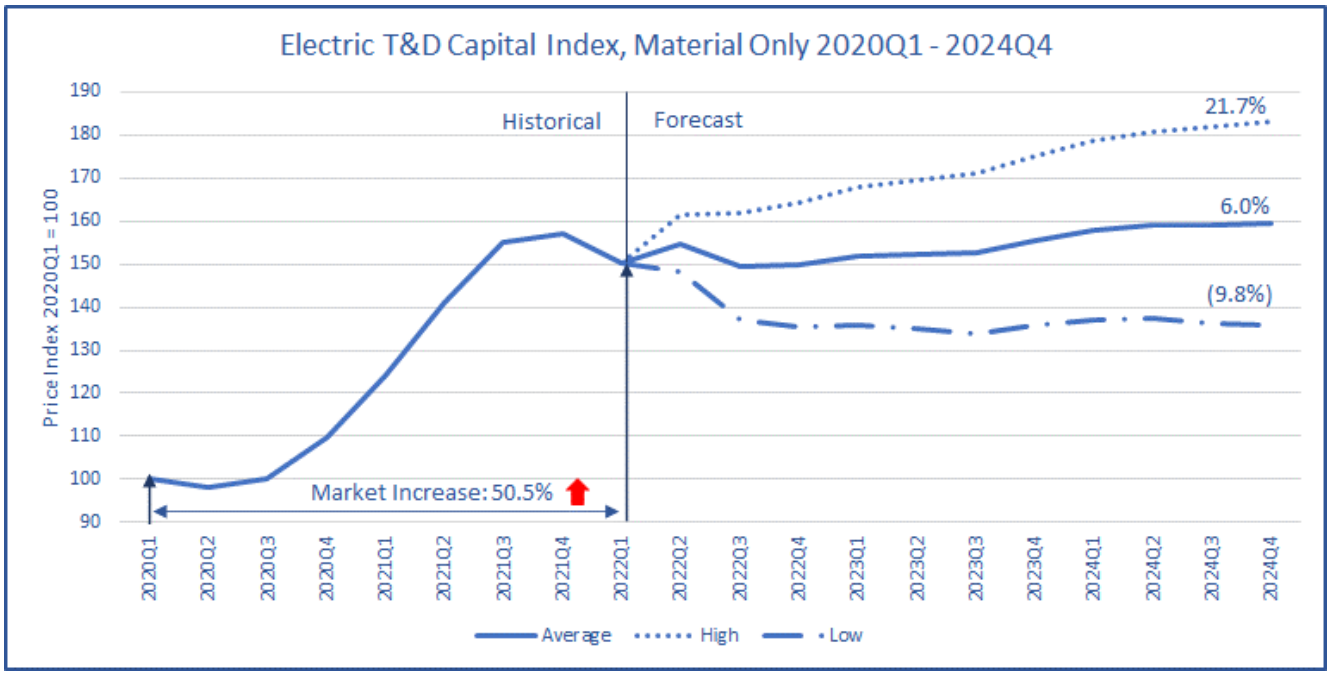
Since execution of FortisBC's MRP (Q1 2020 – Q1 2022), market factors have caused an escalation in capital costs for electric T&D of 17.5%. Forward-looking forecasts for Q1 2022 – Q4 2024 average 7.9%. Table 1 shows the ten most impactful commodities and services in the electric T&D model, and their individual escalations since the beginning of the MRP. Sharp increases in steel and aluminum prices starting in Q3 2020 drove escalations through Q3 2021. Prices of steel and aluminum have leveled off since Q4 2022 which is reflected in the forecast through 2024. The total market split for Electric T&D between labour and materials is 65% and 35% respectively. Labour costs are expected to continue to rise, while material costs level out.

Electric Transmission and Distribution - Labour 2020Q1-2024Q4



**Forecasted percentage increases or decreases are based on index 2022Q1 = 100

Electric Transmission and Distribution - Material 2020Q1-2024Q4



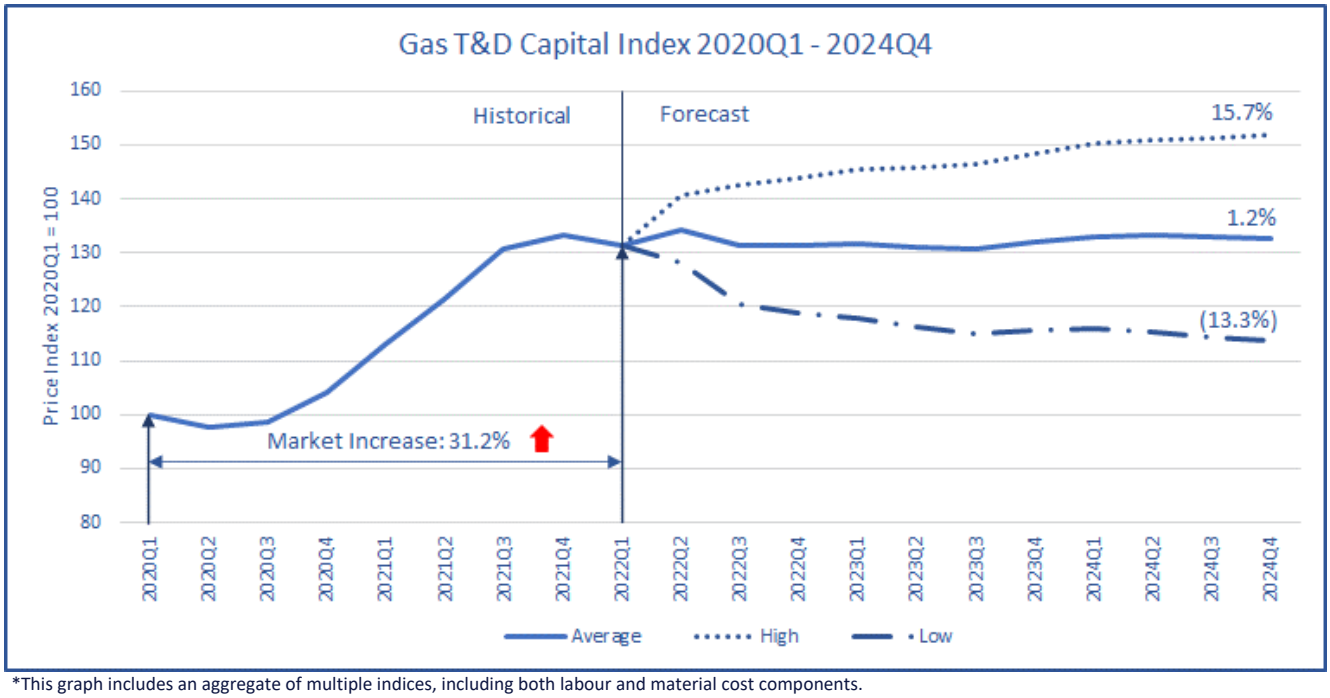
**Forecasted percentage increases or decreases are based on index 2022Q1 = 100

Table 1. Electric T&D High-impact Commodities and Services

Electric T&D High Impact Commodities and Services	Q1 2020 – Q2 2022 (%)
AHE: Mechanical and Electrical Trades, Basic Construction Union Wages, BC	1.5
AHE: Construction, Private Compensation, BC	10.8
ECEC: Benefits, Private Construction	3.3
SPM: Steel, Hot-Rolled Coil	117.3
PPI: Cement, Canada	(3.4)
AHE: Heavy Equipment Operator, Basic Construction Union Wages, BC	2.6
AWE: Repair and Maintenance, BC	4.3
SPM: Aluminum, High Grade	83.2
PPI: Springs and Wire Products, Canada	42.2
IM: Transmission Conductor	160.4

AHE: Average Hourly Earnings, Employer Costs for Employee Compensation, SPM: Spot Price Metal, IPPI: Producer Price Index, AWE: Average Weekly Earnings, IM: Industry Margin

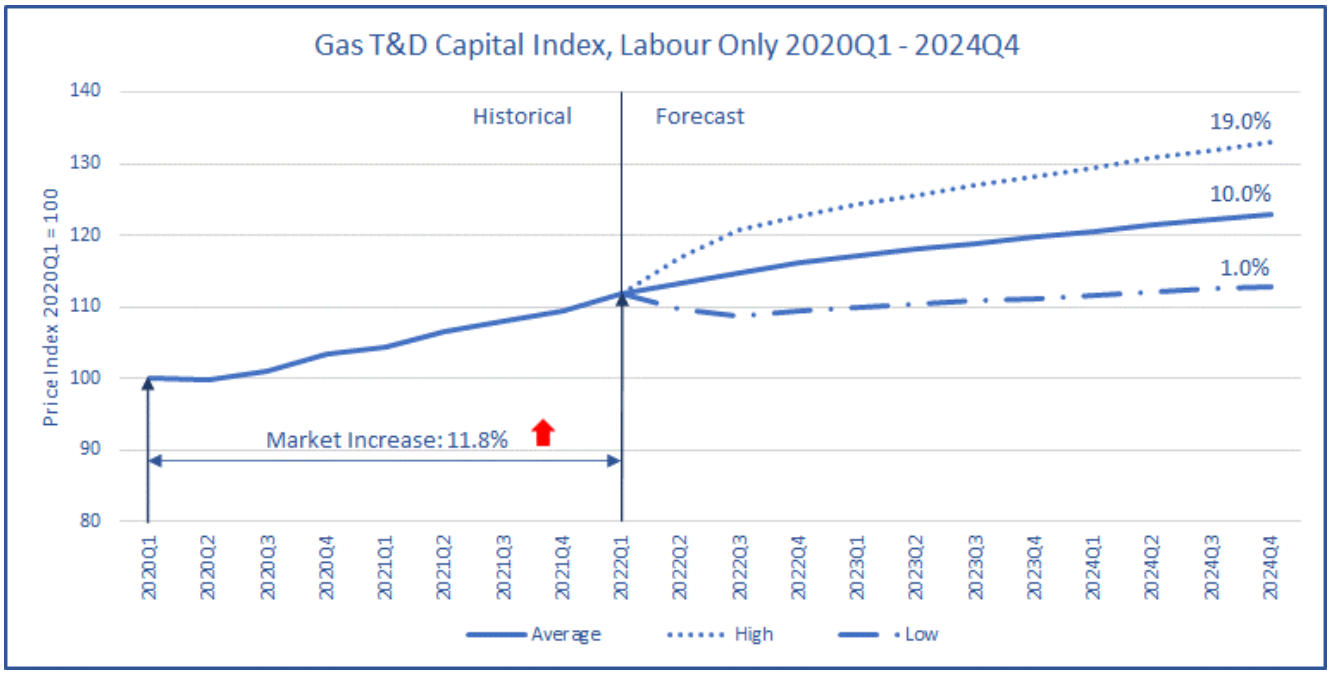
Gas Transmission and Distribution 2020Q1 – 2024Q4



*This graph includes an aggregate of multiple indices, including both labour and material cost components.
**Forecasted percentage increases or decreases are based on index 2022Q1 = 100

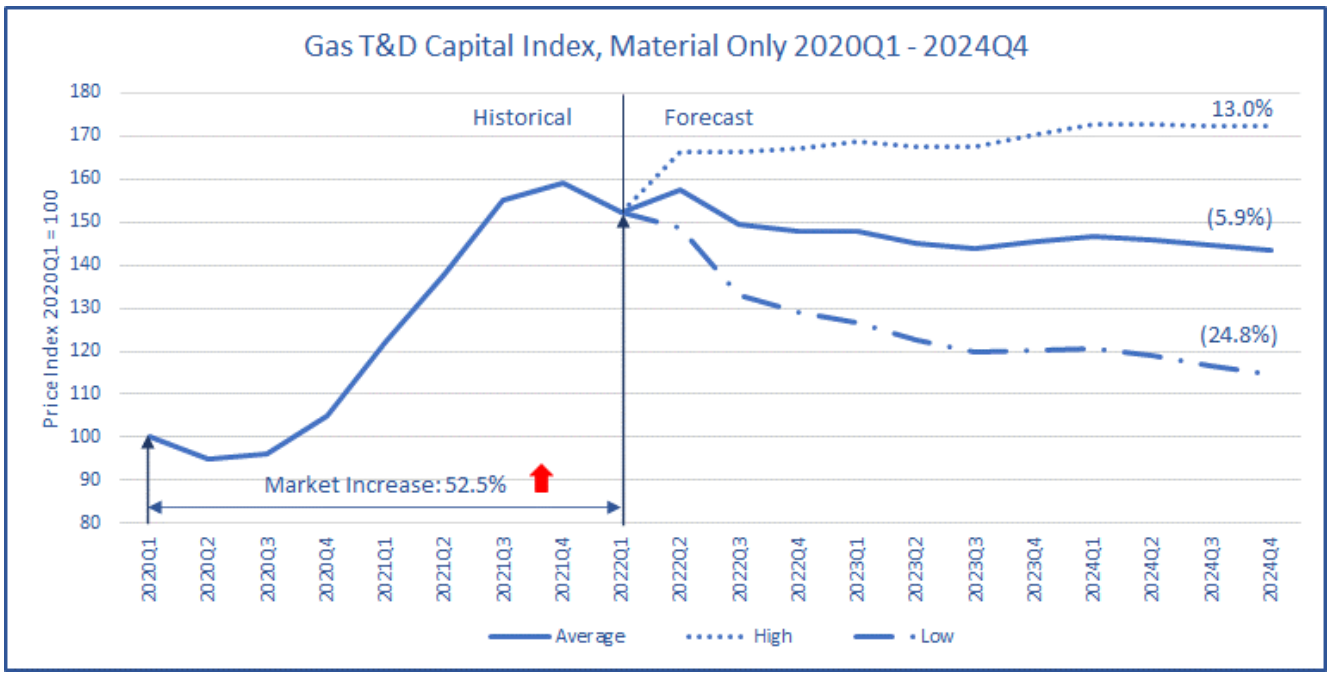
Since execution of FortisBC's MRP (Q1 2020 – Q1 2022), market factors have caused an escalation in capital costs for gas T&D of 31.2%. Forward-looking forecasts for Q1 2022 – Q4 2024 average 1.2%. Table 2 shows the ten most impactful commodities and services in the gas T&D model, and their individual escalations since the beginning of the MRP. Sharp increases in steel and aluminum prices starting in Q3 2020 drove escalations through Q3 2021. Prices of steel and aluminum have leveled off since Q4 2022 which is reflected in the forecast through 2024. The total market split for Gas T&D Construction between labour and materials is 44% and 56% respectively. Labour costs are expected to continue to rise, while material costs are expected to drop slightly, driven by declining steel prices.

Gas Transmission and Distribution - Labour 2020Q1 – 2024Q4



**Forecasted percentage increases or decreases are based on index 2022Q1 = 100

Gas Transmission and Distribution - Material 2020Q1 – 2024Q4



**Forecasted percentage increases or decreases are based on index 2022Q1 = 100

Table 2. Gas T&D High-impact Commodities and Services

Gas T&D High Impact Commodities and Services	Q1 2020 – Q2 2022 Escalation (%)
AHE: Construction, Private, Compensation, BC	10.8
SPM: Steel Plate, Cut-to-Length	173.7
SPM: Steel, Hot-Rolled Coil	117.3
PPI: Hand and Edge Tools	2.7
PPI: Commercial and Industrial Machinery and Equipment Rental	(2.2)
AHE: Professional, Scientific and Technical Services, BC	11.6
SPM: Steel Plate, Coiled	117.3
AHE: Architectural and Finishing Trades, Basic Construction, BC	1.4
AHE Manufacturing, BC	9.8
PPI: Metal Building and Construction Materials, Canada	51.1

AHE: Average Hourly Earnings, SPM: Spot Price Metal, PPI: Producer Price Index

Pre-MRP Market Escalations

The market conditions for both electric and gas T&D vary significantly from the five years prior to the execution of the MRP. Table 3 uses the same models as above to observe the market between Q1 2015 through Q4 2019. Two years (2015 and 2019) experienced a decrease in market price, and the total escalations over this period were 7.6% and 7.5% for electric T&D and gas T&D, respectively.

Table 3. Annual Market Adjustments for Electric and Gas T&D

Year Q1 – Q4	Electric T&D Market Change (%)	Gas T&D Market Change (%)
2019	(0.2)	(3.6)
2018	1.0	4.5
2017	1.8	1.2
2016	4.1	3.6
2015	(1.7)	(3.5)

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Appendix C2

Project Descriptions for Forecast Growth and Sustainment Capital

August 2022

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1. INTRODUCTION

In this appendix, FBC provides descriptions of growth and sustainment capital projects over $1 million.

As described in Section 7 of the Application, FBC's growth capital is divided into the following portfolios:

1. Transmision Growth;
2. Distribution Growth; and
3. New Connects.

FBC's sustainment capital is divided into the following portfolios:

1. Generation;
2. Transmission Sustainment;
3. Stations Sustainment;
4. Distribution Sustainment; and
5. Telecommunications.

The projects over $1 million in each of these categories are described below.

2. GROWTH CAPITAL

2.1 *TRANSMISSION GROWTH*

Regular Transmission Growth capital consists of discrete projects as dictated by transmission system capacity requirements based on forecast load for adequate supply during periods of peak demand and adverse weather conditions.

The table below shows the original spend profile of the projects greater than $1 million in this category during the MRP term, as provided in the MRP Application.[1]

[1] MRP Application, Section 3.4.1.1.1, Table C3-23, pp. C-82 and C-83.

Table C2-1: FBC Transmission Growth Capital Expenditures on Projects Greater than $1 million in MRP Application ($000s)

	2020	2021	2022	2023	2024
Sexsmith 2nd Transformer Addition	4,633	-	-	-	-
Summerland Transformer Replacement	539	2,063	-	-	-
Beaver Park Substation Upgrade	-	-	2,740	5,195	-
DG Bell 2nd Transformer Addition	-	-	-	-	1,086

The table below shows the updated forecast spend profile of the projects greater than $1 million in this category during the MRP term.

Table C2-2: Updated FBC Transmission Growth Capital Expenditures on Projects Greater than $1 million ($000s)

	2020	2021	2022	2023	2024
Sexsmith 2nd Transformer Addition	5,311	66	-	-	-
Beaver Park Substation Upgrade	-	636	4,936	6,223	-
Duck Lake 2nd Transformer Addition	-	-	-	-	1,088

Each of these projects is described further below.

- **Sexsmith Second Transformer Addition:** Peak load on the existing 32 MVA Sexsmith T1 transformer was forecast to exceed nameplate capacity in 2020. In order to continue to maintain the current levels of reliability and meet the planning criteria for this area of Kelowna, a second transformer was installed and put into service at the Sexsmith substation in 2020. The actual costs of this project were approximately $5.3 million with the bulk of capital expenditures occurring in 2020.
- **Summerland Transformer Replacement:** The existing 20 MVA Summerland substation transformer supplies one of two wholesale delivery points to the District of Summerland municipal utility. Due to anticipated new commercial development in Summerland, peak load at this wholesale delivery point was previously forecast to exceed 95 percent of the contract demand limit during the MRP term. Since the most recent load forecast projects that peak load will not exceed this threshold until 2026, no project expenditures are planned during the MRP term. FBC will continue to engage with the District of Summerland municipal utility to discuss options to increase wholesale capacity. This project is thus not included in Table C2-2.
- **Beaver Park Substation Upgrade:** This project is driven by load growth in the Trail area and equipment condition issues as the BEP T1 transformer tap changer cannot be adequately maintained. The project seeks to rebuild the Beaver Park substation on an expanded station footprint. To meet planning criteria and continue to provide a reliable supply, the existing transformer will be replaced, and a second transformer will be installed. The estimated total project cost including direct overhead is approximately $11.8

million. The total project costs have increased since the MRP Application filing in 2019 due to several factors, including archaeological requirements and increases in engineering, materials and construction costs. Commodity cost increases have placed significant pressure on materials.

- **Duck Lake Second Transformer Addition:** This project is driven by significant development occurring in the area served by the Duck Lake substation. FBC planning studies indicate that a second distribution transformer is required at Duck Lake to maintain the current level of reliability and support distribution contingency planning criteria. As the pace and scale of development has exceeded what was anticipated when the MRP Application was filed, this project has now been advanced ahead of the DG Bell project described below. The estimated cost of this project is $5.3 million; however, the cost could increase further as a result of potential commodity cost increases impacting the cost of materials.
- **DG Bell Second Transformer Addition:** FBC planning studies indicate that a second distribution transformer is required at DG Bell to maintain the current level of reliability and support distribution contingency planning criteria. This project has been deferred from the original 2024-25 construction schedule to accommodate the Duck Lake Second Transformer Addition. This project is now planned for 2025-26 with an estimated in-service date of 2026. This project is thus not included in Table C2-2.

2.2 *DISTRIBUTION GROWTH*

Similar to its transmission system, FBC evaluates distribution system capacity on an annual basis, based on the projected loads. FBC's Distribution Growth capital includes two ongoing programs, small (planned) growth projects and unplanned growth projects. Larger individual distribution growth projects are also included.

The table below shows the original spend profile of the projects greater than $1 million in this category during the MRP term, as provided in the MRP Application.[2]

Table C2-3: FBC Distribution Growth Capital Expenditures on Projects Greater than $1 million in MRP Application ($000s)

	2020	2021	2022	2023	2024
DG Bell Feeder 4 Addition	1,970	-	-	-	-

The table below shows the updated forecast spend profile of the projects greater than $1 million in this category during the MRP term.

[2] MRP Application, Section 3.4.1.1.2, Table C3-24, pp. C-83 and C-84.

Table C2-4: Updated FBC Distribution Growth Capital Expenditures on Projects Greater than $1 million ($000s)

	2020	2021	2022	2023	2024
DG Bell Feeder 4 Addition	-	26	1,870	-	-
Huth CoP 13KV Supply	1,219	62	-	-	-

Each of these projects is described further below.

- **DG Bell Feeder 4 Addition:** This project was deferred due to the timing of City of Kelowna road construction from 2020 to 2022; however, the total actual project cost is lower than forecast in the MRP Application.
- **Huth CoP 13KV Supply:** This project was added in 2020. The project was required to ensure that FBC continues to meet the terms of its Wholesale Agreement with the City of Penticton at the Huth substation Point of Delivery.

2.3 *NEW CONNECTS*

There are no projects over $1 million that have been completed or are planned to be completed during the MRP term.

3. SUSTAINMENT CAPITAL

3.1 *GENERATION SUSTAINMENT*

FBC operates and maintains four generating facilities with a total of 15 units. FBC regularly monitors its infrastructure to ensure it meets industry standards and guidelines, complies with regulations, and operates safely to minimize risk to the public and employees. FBC's Generation capital is grouped into four capital programs: (i) Hydraulic Dam Structures; (ii) Generating Equipment; (iii) Generation Auxiliary Equipment; and (iv) Buildings and Structures.

The table below shows the original spend profile of the projects greater than $1 million in this category during the MRP term, as provided in the MRP Application[3].

Table C2-5: FBC Generation Sustainment Capital Expenditures on Projects Greater than $1 million in MRP Application ($000s)

	Category	2020	2021	2022	2023	2024
Concrete Structures Rehabilitation	Hydraulic Dam Structures	685	821	979	1,128	1,019
LBO Spillway Gates Refurbishment	Hydraulic Dam Structures	1,467	1,396	-	-	-

[3] MRP Application, Section 3.4.1.2.1, pp. C-84 to C-88.

	Category	2020	2021	2022	2023	2024
Other Gates Upgrades	Hydraulic Dam Structures	481	100	414	241	545
Dam Safety Instrumentation	Hydraulic Dam Structures	715	765	-	-	806
Guarding of Rotating Parts	Hydraulic Dam Structures	194	324	458	295	287
UBO Unit 6 Turbine Runner Replacement	Generating Equipment	-	35	582	2,035	-
Generator Excitation System and Control Systems	Generating Equipment	-	67	556	556	-
Generator Thrust Bearing Cooling System	Generating Equipment	247	271	295	198	198
Dewatering and Drainage Systems	Generation Auxiliary Equipment	116	349	349	349	349
Station Service Upgrade	Generation Auxiliary Equipment	333	495	286	286	300
COR Annex Building Replacement	Buildings and Structures	-	-	-	198	1,606

The table below shows the updated forecast spend profile of the projects greater than $1 million in this category during the MRP term.

Table C2-6: Updated FBC Generation Sustainment Capital Expenditures on Projects Greater than $1 million ($000s)

	Category	2020	2021	2022	2023	2024
Concrete Structures Rehabilitation	Hydraulic Dam Structures	715	745	1,128	651	1,061
LBO Spillway Gates Refurbishment	Hydraulic Dam Structures	1,436	2,893	-	-	-
Dam Safety Instrumentation	Hydraulic Dam Structures	896	287	1,059	100	100
Rehabilitation of Dam Stability Anchors	Hydraulic Dam Structures	78	442	392	326	-
UBO Unit 6 Turbine Runner Replacement	Generating Equipment	-	22	501	1,395	2,085
Generator Excitation System and Control Systems	Generating Equipment	-	271	344	485	836
Dewatering and Drainage Systems	Generation Auxiliary Equipment	126	217	655	1,166	222

	Category	2020	2021	2022	2023	2024
Station Service Upgrade	Generation Auxiliary Equipment	298	577	834	512	260
COR Annex Building Replacement	Buildings and Structures	4	4	186	200	1,606

Each of these projects is described in further detail below:

- **Concrete Structures Rehabilitation Project:** This is a continuation of the program started in 2014 to address requirements of the BC Dam Safety Regulation and deterioration of concrete structures. The cost for this project is $0.332 million lower than forecast in the MRP Application due mainly to reduced scope at the Lower Bonnington Dam as safety issues are restricting access to lower areas of the construction scaffold in the tailrace during unit start-up. FBC is working on designing a solution to this issue.
- **Lower Bonnington Dam (LBO) Spillway Gates Refurbishment Project:** This project was completed in 2021 at a higher cost than forecast due to complexities encountered during construction and the implementation of a monorail system for the installation of stoplogs that was not considered initially.
- **Other Gates Upgrade Project:** This project is now forecast to cost less than $1 million due to FBC implementing a simpler solution for strengthening the LBO intake superstructure. This project is thus not included in Table C2-6.
- **Dam Safety Instrumentation Project:** This project addresses the requirement in section 19(1) of the BC Dam Safety Regulation for instrumentation to adequately monitor the dam and the area surrounding or adjacent to the dam. The project began in 2018 and includes the installation of dam monitoring systems at FBC's plants. FBC has thus far completed the installation of dam safety instrumentation at LBO and UBO and will complete the installation of dam safety instrumentation at South Slocan (SLC) in 2022. The higher costs are primarily due to higher drilling costs. The installation of the dam safety instrumentation at Corra Linn (COR) has been delayed with only the engineering being planned to occur in 2023-2024.
- **Guarding of Rotating Parts Project:** This project is now forecast to cost less than $1 million due to a reduction in scope. The original forecast included installing guards on spillway and intake gates, but during detail design, more effective administrative and operational methods were developed and implemented which have resulted in cost reductions. This project is thus not included in Table C2-6.
- **Rehabilitation of Dam Stability Anchors:** This project was included in the Other Hydraulic Dam Structures Projects category in the MRP Application, as at the time of filing it was expected to cost less than $1 million. However, the scope of work has increased from $0.302 million to $1.238 million due to damage to the anchors' heads being more extensive and the number of anchor heads that required repairs being higher than initially anticipated; the degree of the anchor head damage could only be established while

inspecting the anchors which are located on the overflow spillway. The rehabilitation of the LBO dam stability anchors will be competed in 2022. Rehabilitation of the COR dam stability anchors will commence in 2023 and will complete in 2025.

- **Upper Bonnington Dam (UBO) Unit 6 Turbine Runner Replacement Project:** This project includes the replacement of the UBO Unit 6 turbine runner that has reached the end of its service life. Work on this project was accelerated to mitigate the anticipated delays in the global supply chain due to the COVID-19 pandemic. The estimated cost of this project is approximately $1.445 million higher than originally forecast due to the costs of the runner being higher. The expected in-service date is December 2024.
- **Generator Excitation System and Control System Replacement Project:** This project addresses the replacement of some of the generator excitation systems beginning in 2022 with Unit 6 at UBO. The updated cost of this project is approximately $0.765 million higher due mainly to higher costs with the procurement of the control and excitation systems.
- **Generator Thrust Bearing Cooling System Upgrade Project:** This project is now forecast to cost less than $1 million as FBC has implemented a better designed solution that has resulted in cost savings. This project is thus not included in Table C2-6.
- **Dewatering and Drainage Systems Rehabilitation Project:** This project was budgeted based on costs including rehabilitation of pipes valves and other components of the dewatering and drainage systems. During detail design it was discovered that this solution was not feasible and a new solution was designed and is being implemented which is based on a pump in gate design that has an increased cost of $0.690 million. The first system is planned to be put in service at SLC in 2023 and engineering for the next plant will occur in 2024.
- **Station Service Upgrade Project:** This project includes upgrading the protection system of FBC's station service system and neutral grounding in order to address safety hazards, replacement of station service transformers that have reached the end of their service life and other small station service improvements. The estimated cost of this project is $0.186 million higher due to the need to address deficiencies related to LBO powerhouse grounding and bonding issues that were uncovered while doing investigations in 2021.
- **Corra Linn Annex Building Replacement Project:** FBC has decided to start the preliminary engineering in 2022 and is planning to complete the project in 2024.

3.2 *TRANSMISSION SUSTAINMENT*

Transmission Sustainment expenditures are required to proactively manage the condition and integrity of FBC's transmission line facilities, manage the risk to employees and public safety, and maintain an acceptable level of service for customers.

The table below shows the original spend profile of the projects greater than $1 million in this category during the MRP term, as provided in the MRP Application[4].

Table C2-7: FBC Transmission Sustainment Capital Expenditures on Projects Greater than $1 million in MRP Application ($000s)

	2020	2021	2022	2023	2024
30 Line Rehabilitation	1,100	-	-	-	-
30, 32, 19 Lines Right of Way	647	651	658	656	652

The table below shows the updated forecast spend profile of the projects greater than $1 million in this category during the MRP term.

Table C2-8: Updated FBC Transmission Sustainment Capital Expenditures on Projects Greater than $1 million ($000s)

	2020	2021	2022	2023	2024
30 Line Rehabilitation	1,087	91	-	-	-
30, 32, 19 Lines Right of Way	458	637	652	652	648

Each of these projects is described in further detail below:

- **30 Line Rehabilitation between the South Slocan and Coffee Creek Substations:** This project included expenditures for structural stabilization of the transmission line, based on the 2018 condition assessment, including stubbing poles and replacing poles and cross-arms. The project was completed as planned in 2020.
- **30, 32 and 19 Line Right of Way Improvements:** The scope of this multi-year project involves acquiring an additional right of way predominantly upslope of the existing right of way for 30 Line (Nelson to Coffee Creek Substation), 32 Line (Creston to Crawford Bay), and 19 Line (Slocan Valley) and clearing the additional right of way to reduce the number of tree-related outages. Portions of these lines are in steep terrain. Of FBC's 72 transmission lines, tree contacts on 30 Line account for 17 percent of the transmission related outages. Tree contacts on 32 Line and 19 Line each account for approximately 8 percent of FBC's transmission related outages. These projects are in progress, with FBC implementing land owner agreements to widen the right of way.

3.3 *STATIONS SUSTAINMENT*

FBC's substation sustainment capital expenditures are driven by a combination of time-based and condition-based scheduling. Currently, FBC employs a substation Computerized Maintenance Management System (CMMS) which tracks basic equipment data and condition information for FBC's substation assets and is used to assist in scheduling maintenance tasks.

[4] MRP Application, Section 3.4.1.2.2, pp. C-89 and C-90.

The table below shows the original spend profile of the projects greater than $1 million in this category during the MRP term, as provided in the MRP Application.[5]

Table C2-9: FBC Stations Sustainment Capital Expenditures on Projects Greater than $1 million in MRP Application ($000s)

	2020	2021	2022	2023	2024
AS Mawdsley Tranformer Replacement	-	-	-	-	3,802
Trout Creek Transformer Replacement	2,263	-	-	-	-
Kaleden Transformer Replacement	-	-	-	-	2,716
Salmo Station Upgrade	3,718	7,154	-	-	-
Fruitvale Station Upgrade	-	-	-	-	3,802

The table below shows the updated forecast spend profile of the projects greater than $1 million in this category during the MRP term.

Table C2-10: Updated FBC Stations Sustainment Capital Expenditures on Projects Greater than $1 million ($000s)

	2020	2021	2022	2023	2024
Trout Creek Transformer Replacement	153	2,660	1,568	-	-
Keremeos 2nd Transformer Addition	-	-	-	543	2,700
Salmo Station Upgrade	4,778	5,143	-	-	-
Fruitvale Station Upgrade	-	-	-	1,087	7,021

Each of these projects is described in further detail below:

- **AS Mawdsley Transformer Replacement:** FBC is now planning to file a Certificate of Public Convenience and Necessity (CPCN) application for this project as the cost is forecast to be above the $20 million materiality threshold. This project is thus not included in Table C2-10.
- **Trout Creek Transformer Replacement:** This project is driven by asset condition, as the transformer is 52 years old and uses the most unreliable Load Tap Changer (LTC) in the FBC fleet (Pioneer TC546). The acetylene levels and a barrel collecting the excess oil moving from the main tank to LTC indicated a cracked LTC terminal board. The project is currently in execution with an estimated in-service date of 2022. Increases in project costs are due to delays related to the lands purchase and ALR approval, along with significant additional work related to other end of life station equipment. Further

[5] MRP Application, 3.4.1.2.3, Tables C3-34 and C3-35, pp. C-91 to C-93.

investigation of the station after the MRP proceeding revealed that the entire station was in a similar condition as the transformer which resulted in a rebuild of the station.

- **Keremeos Second Transormer Addition:** This project is driven by asset condition. The Keremeos transformer has a 48 year old LTC that is not functioning. Based on the resulting operational challenges with the control of customer voltages, this transformer replacement is a high priority.
- **Kaleden Transformer Replacement:** This project has been deferred until after the end of the MRP term to accommodate the previously unforeseen Keremeos Transformer Replacement project. The existing Keremeos transformer presents a larger risk at this time, but planning remains underway for replacement of the Kaleden transformer in 2025-26. This project is thus not included in Table C2-10.
- **Salmo Station Upgrade:** This project was driven by equipment condition issues and aging infrastructure at the Salmo and Ymir substations. The project rebuilt the Salmo substation on the existing station footprint and decommissioned the Ymir substation. The Ymir substation customers were permanently transferred to the Salmo substation. Construction began in 2020 and was completed in 2021. The total cost of this project was $9.9 million. The overall total project cost was less than forecast due primarily to lower actual costs for the distribution and transmission line work. The replacement of the Salmo Station 13 kV Switchgear was also included in this project.
- **Fruitvale Station Upgrade:** This project is driven by equipment condition issues and aging infrastructure at the Fruitvale and Hearns substations. The Hearns single phase transformer units are approximately 72 years old, and the Fruitvale metal-clad switchgear is approximately 55 years old; this equipment is at risk of failing. The project seeks to rebuild and relocate the Fruitvale substation, while decommissioning the Hearns substation. The Hearns substation customers would be permanently transferred to the Fruitvale substation. The existing Fruitvale substation footprint is too small to accommodate the rebuild, and land will need to be acquired for the upgrade. To meet planning criteria and continue to provide a reliable supply to the Fruitvale area, the existing transformer will be replaced, and a second transformer will be installed. The estimated total project cost including direct overhead is $12.5 million. FBC forecasts spending $1.1 million in 2023, $7.0 million in 2024, and $4.4 million in 2025 with an estimated in-service date of 2025. The total project costs have increased since the MRP Application due to several factors, including land acquisition requirements and increases in engineering, material and construction costs.

3.4 *DISTRIBUTION SUSTAINMENT*

There are no projects over $1 million that have been completed or are planned to be completed during the MRP term.

3.5 TELECOMMUNICATIONS SUSTAINMENT

FBC's telecommunications system is an integral component in the protection relaying system, remedial action schemes, substation operations and control, and generation dispatch systems. The system requires ongoing investment to replace aging or failed systems for safe and reliable operation of the system and to ensure business needs continue to be met.

The table below shows the original spend profile of the projects greater than $1 million in this category during the MRP term, as provided in the MRP Application[6].

Table C2-11: FBC Telecommunications Sustainment Capital Expenditures on Projects Greater than $1 million in MRP Application ($000s)

	Category	2020	2021	2022	2023	2024
Backbone Transport Technology Migration	Systems Upgrades and Replacements	-	-	937	953	-
SCADA System Replacement	Systems Upgrades and Replacements	-	1,086	2,192	2,188	1,086
VHF Radio System Replacement	Systems Upgrades and Replacements	-	-	548	875	-

The table below shows the updated forecast spend profile of the projects greater than $1 million in this category during the MRP term.

Table C2-12: Updated FBC Telecommunications Sustainment Capital Expenditures on Projects Greater than $1 million ($000s)

	Category	2020	2021	2022	2023	2024
Backbone Transport Technology Migration	Systems Upgrades and Replacements	-	-	-	841	853
SCADA System Replacement	Systems Upgrades and Replacements	-	-	-	543	1,080
VHF Radio System Replacement	Systems Upgrades and Replacements	-	-	-	-	540

Each of these projects is described in further detail below:

- **Backbone Transport Technology Migration:** This project will replace FBC's existing SONET network with a new high-speed data network supporting all present and anticipated future applications needed to provide safe and reliable service. The project, which was originally forecast to start in 2022, is now expected to commence in 2023.
- **SCADA System Replacement Project:** This project was planned to start in 2021; however, due to limited resources the business analysis was not initiated until late 2021,

[6] MRP Application, Section 3.4.1.2.5, pp. C-99 to C-101.

resulting in delays to determine the best SCADA solution. The estimated cost of this project has decreased to approximately $6 million.

- **VHF Radio System Replacement Project:** The existing FBC Electric VHF Radio system is at the end of its service life (>20 years old) and the technology is obsolete. Parts are still available but are becoming more difficult to source and the legacy technology is difficult to support as new hires are not trained or experienced with the legacy technology. New 2-way radio technologies bring significant benefits with respect to sharing of channels, ease of maintenance, superior coverage and ability to send data in addition to voice. In 2024, the first stages of the VHF radio replacement project are expected to start, with the project continuing into 2025.

Appendix D
DRAFT ORDER

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British Columbia
Utilities Commission

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ORDER NUMBER
G-xx-xx

IN THE MATTER OF
the *Utilities Commission Act*, RSBC 1996, Chapter 473

and

FortisBC Inc.
Annual Review for 2023 Rates

BEFORE:
E. B. Lockhart, Panel Chair
C. M. Brewer, Commissioner
A. Pape-Salmon, Commissioner

on Date

ORDER

WHEREAS:

A. On June 22, 2020, the British Columbia Utilities Commission (BCUC) issued its Decision and Order G-166-20 approving a Multi-Year Rate Plan (MRP) for 2020 through 2024 (2020-2024 MRP Decision) for FortisBC Inc. (FBC). In accordance with the 2020-2024 MRP Decision, FBC is to conduct an annual review (Annual Review) process to set its rates for each year;

B. By letter dated June 28, 2022, FBC proposed a regulatory timetable for the Annual Review of its 2023 rates;

C. By Order G-193-22 dated July 15, 2022, the BCUC established the regulatory timetable for the Annual Review of FBC's 2023 rates, which included FBC filing its Annual Review materials, intervener registration, one round of information requests, a workshop, FBC's responses to undertakings at the workshop, and written final and reply arguments;

D. On August 5, 2022, FBC submitted its materials for the Annual Review for 2023 Rates Application (Application). In the Application, FBC requests a 3.99 percent rate increase over 2022 rates, effective January 1, 2023, among other things; and

E. The BCUC has reviewed the Application, evidence and arguments filed in the proceeding and makes the following determination.

NOW THEREFORE pursuant to sections 59 to 61, 89 and 99 of the *Utilities Commission Act*, for the reasons stated in the decision issued concurrently with this order, the BCUC orders as follows:

1. FBC is approved to recover the 2023 revenue requirement and resultant rate change on an interim basis, effective January 1, 2023, as filed in the Application and subject to any adjustments identified by FBC during

the regulatory process and from any directives or determinations made by the BCUC in its decision on the Application. Rates will remain interim pending the outcomes of Stage 1 of the BCUC's current generic cost of capital (GCOC) proceeding and FBC's 2023-2027 Demand Side Management (DSM) Plan proceeding.

2. The level of forecast growth, sustainment and other capital to be incorporated in rates for the years 2023 and 2024, as set out in Section 7.2.1, is approved.

3. FBC is approved to:

    a. Create a rate base deferral account for the 2023 Joint Pole Use Audit and amortize the deferral account over five years commencing January 1, 2023; and

    b. Amortize the existing COVID-19 Customer Recovery Fund Deferral Account over three years commencing January 1, 2023.

4. FBC is approved to cease reporting on the COVID-19 Customer Recovery Fund Deferral Account.

5. Directive 6 of Order 42-21 is varied as follows: "FBC is approved to record COVID-19 incremental costs and related savings from 2020 and 2021 into the Flow-through deferral account".

6. Directive 2 of Order G-83-14 is varied as follows: "Approval is granted until such time as FBC no longer has an exemption to prepare and file its financial statements in accordance with US GAAP or is no longer reporting under US GAAP for financial reporting purposes".

7. FBC is directed to file with the BCUC as a compliance filing, within 15 days of the issuance of this order, amended tariff pages and finalized financial schedules for 2023, in accordance with the terms of this order.

DATED at the City of Vancouver, in the Province of British Columbia, this (XX) day of (Month Year).

BY ORDER

(X. X. last name)
Commissioner

FBC 2024 ANNUAL REVIEW OF RATES
EXHIBIT B-2

Sarah Walsh
Director, Regulatory Affairs

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August 4, 2023

British Columbia Utilities Commission
Suite 410, 900 Howe Street
Vancouver, BC
V6Z 2N3

Attention: Patrick Wruck, Commission Secretary

Dear Patrick Wruck:

Re: FortisBC Inc. (FBC)

Multi-Year Rate Plan for 2020 through 2024 approved by British Columbia Utilities Commission (BCUC) Order G-166-20 (MRP Plan)

Annual Review for 2024 Rates

In accordance with the MRP Plan and BCUC Order G-191-23 setting out the Regulatory Timetable for FBC's Annual Review, FBC hereby attaches its Annual Review for 2024 Rates Application materials.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC INC.

Original signed:

Sarah Walsh

Attachments

cc (email only): Registered Interveners in the FBC Annual Review for 2023 Rates proceeding.

FORTIS BC™

FORTISBC INC.

Multi-Year Rate Plan for 2020 through 2024

Annual Review for 2024 Rates

August 4, 2023

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1. APPROVALS SOUGHT, OVERVIEW OF THE APPLICATION AND PROPOSED PROCESS

1.1 INTRODUCTION

FortisBC Inc. (FBC or the Company) files this Application in compliance with British Columbia Utilities Commission (BCUC) Order G-166-20, which approved a Multi-Year Rate Plan (MRP or the Plan) for FBC for the years 2020 to 2024. In accordance with the MRP, an annual review process is required to set rates for each year of the MRP.

The MRP provides stable levels of O&M funding and includes service quality indicators (SQIs) to monitor the maintenance of service quality. The approved Earnings Sharing Mechanism (ESM), set out in Section 10, aligns the incentive properties of the Plan between customers and the Company.

As explained in Section 10 of the Application, FBC proposes to distribute $2.396 million pre-tax ($1.749 million after-tax) in earnings sharing to customers in 2024.

The proposed rates for 2024 flowing from the forecasts and approved formulas set out in the Application, including returning the actual 2022 earnings sharing to customers, result in a 4.83 percent rate increase from 2023 rates. The increase is primarily due to an increase in power purchase expense (PPE), followed by an increase in income tax expense.

In the subsections below, FBC sets out the approvals it is seeking and provides an overview of the requirements for the annual review process. This is followed by a discussion of FBC's 2022 formula O&M savings and the productivity initiatives that FBC is developing. Finally, FBC provides a summary of its proposed revenue requirements and rate changes for 2024 and a summary of the SQI results. These matters are addressed in more detail in subsequent sections of the Application.

1.2 APPROVALS SOUGHT

With this Application, FBC requests BCUC approval for the following pursuant to sections 59 to 61 of the *Utilities Commission Act* (UCA):

1. Approval to recover the 2024 revenue requirement and resultant rate change on a permanent basis, effective January 1, 2024, as filed in the Application and subject to any adjustments identified by FBC during the regulatory process and from any directives or determinations made by the BCUC in its decision on the Application.
2. Creation of the following rate base deferral accounts, as described in Section 7.6:
    - 2025 Multi-year Rate Plan (MRP) Application deferral account, with the amortization period to be determined in a future proceeding;

- 2024 Mandatory Reliability Standards (MRS) Audit deferral account, with an amortization period of three years, commencing January 1, 2024;
- PST Rebate on Select Machinery and Equipment deferral account, with an amortization period of one year, commencing January 1, 2024;
- BC Cost of Living Credit deferral account, with an amortization period of one year, commencing January 1, 2024; and
- Climate Change Operational Adaptation (CCOA) Plan deferral account, with an amortization period of four years, commencing January 1, 2024.

A draft order is included in Appendix C.

1.3 REQUIREMENTS FOR THE ANNUAL REVIEW

On page 167 of the MRP Decision, the BCUC set out its expectations for the Annual Review component of the MRP. For reference, the table below sets out each requirement and FBC's response or where it is addressed in the Application.

Table 1-1: Annual Review Requirements

Item	Description	Response or Reference
1	Review of the current year projections and the upcoming year's forecast. For further clarity, these items are listed below:	See items 1(a) to 1(f) below
1(a)	Customer growth, volumes and revenues;	Section 3
1(b)	Year-end and average customers, and other cost driver information including inflation;	Section 2
1(c)	Expenses, determined by the indexing formula plus items forecast annually;	Section 6
1(d)	Capital expenditures (as provided for by the capital forecast), plus other items forecast annually;	Section 7
1(e)	Plant balances, deferral account balances and other rate base information and depreciation and amortization to be included in rates; and	Sections 7 and 12
1(f)	Projected earnings sharing for the current year and true-up to actual earnings sharing for the prior year.	Section 10
2	Identification of any efficiency initiatives that the Utilities have undertaken, or intend to undertake, that require a payback period extending beyond the MRP period with recommendations to the BCUC with respect to the treatment of such initiatives.	FBC has not identified any efficiency initiatives with a payback beyond the end of the MRP period
3	Review of any exogenous events that the Company or stakeholders have identified that should be put forward to the BCUC for review.	Section 12.2
4	Review of the Utilities' performance with respect to SQIs. Bring forward recommendations to the BCUC where there have been a "sustained serious degradation" of service.	Section 13

Item	Description	Response or Reference
5	Assess and make recommendations with respect to any SQIs that should be reviewed in future Annual Reviews.	FBC does not have any recommendations at this time
6	Reporting on the Innovation Fund status.	Not Applicable for FBC
7	Assess and make recommendations to the BCUC on potential issues or topics for future Annual Reviews.	FBC does not have any recommendations at this time

1.4 FORMULA O&M SAVINGS AND PRODUCTIVITY INITIATIVES

1.4.1 Overview of 2022 Formula O&M Savings

For 2022, FBC achieved formula O&M savings in addition to meeting the embedded productivity improvement factor in the O&M formula. Total formula O&M savings before earnings sharing were approximately $3.7 million, excluding the COVID-19 pandemic approved exogenous factor credit for net O&M cost reductions of approximately $1.0 million.

Of the approximate $3.7 million in formula O&M savings realized in 2022, approximately $3 million are due to labour savings, including overtime. The remaining savings are due to a variety of factors including reduced postage and printing costs from paperless billing and general timing of non-labour expenditures. While some of the savings are one-time in nature (e.g., required time to fill vacancies from turnover), some of the savings are expected to continue into the future, recognizing that cost pressures in the future may offset the savings.

FBC will continue to pursue productivity improvements to achieve savings beyond the productivity improvement factor as it seeks to manage its business needs and cost pressures resulting from its evolving and challenging operating environment.

1.4.2 Productivity Initiatives

As described in FBC's Annual Review for 2022 Rates, in 2021, FBC and FortisBC Energy Inc. (together FortisBC) initiated a working group consisting of senior managers and directors from different parts of the organization that is responsible for reviewing and identifying productivity initiatives. Following is a summary of these productivity initiatives.

1. **Field Operations Improvements:** A review of the meter reading routes was undertaken and updated to achieve optimized routes, resulting in reduced overtime and increased employee safety. In addition to optimizing meter reading routes, range extenders continue to be added to reduce the number of manual meter reads required, resulting in reduced travel time for meter readers and consistent, reliable meter readings for customers. Additionally, Operations is undertaking work to accurately map meters to their corresponding transformer which has operational benefits. Mapping the transformer-to-meter relationship provides accurate capacity information which can be used to determine

where EV charging load growth is and where it can be added to utilize existing infrastructure. Another benefit is that customer outage mapping improves the ability for technicians to more effectively and quickly troubleshoot system trouble calls.

2. **Use of Unmanned Aerial Vehicles (UAVs - Drones):** FBC's contract resources that are tasked with performing transmission line condition assessments continue to rely on the use of UAVs to aid in the completion of this work. Although UAVs have not eliminated the need for human resources to complete condition assessment work, primarily due to limitations on the operation of UAVs beyond visual line of sight, they have allowed FBC to reduce the need for follow-up bucket truck inspections to confirm deficiencies that cannot be fully assessed from a ground-based inspection. Additionally, FBC has equipped its Operations crews with small drones that allow for visual inspections during trouble or outage events where ground access may be difficult or restricted. FBC will continue to monitor industry developments regarding the use of UAVs for supporting utility operations.

3. **Data Analytics:** This is an initiative to centralize the Company's data sources coupled with a suite of analytic tools to analyze and use the data to inform decision-making. FortisBC uses data to inform decision making, but its current data is spread across dozens of disparate systems. Data is often siloed within departments and the volume, variety, and velocity of data coming into FortisBC is increasing. It can be difficult and time consuming to gather, clean, and filter the data needed to create useful information. As part of the solution, Enterprise Analytics creates a data fabric atop core FortisBC source and storage systems to facilitate advanced analytics opportunities. It addresses key barriers by integrating existing data into a single, scalable platform to deliver easily accessible and reliable data. It also simplifies connecting data assets to reduce cost and effort to create reports that can be easily updated and enables automation of reporting. Enterprise Analytics enables improvement in key performance indicators selected by each business area, and provides enhanced data quality, and work efficiency. Benefits are realized from shared information and sharing of insight across business units. Additionally, quality assurance is better enabled as information is reconciled and standardized.

   In 2022, efforts focused on developing solutions for three business areas: Customer Service, Major Projects, and Energy Supply. For Customer Service, Enterprise Analytics is delivering a new reporting dashboard displaying key Customer Service data all in one place (gas and electric). Benefits include providing a clear and easily accessible view of factors contributing to performance, insights identifying strengths and opportunities to grow FortisBC's relationships with its customers, operational savings through more efficient customer interactions, and less effort to share metrics with parties outside of customer service. This is only the starting point, as more data sources could be included, and new ways of using the dashboard will be discovered, providing the potential to optimize continuous improvement with additional available, integrated data. For the Major Projects area, Enterprise Analytics is enabling it to provide analytical insight through dashboarding and reporting on Major Projects project budgets, schedule, and project development. Lastly, for the Energy Supply area, Enterprise Analytics is providing analytic

insights for energy loss, broadly accounting for power at different points within the FBC electricity supply chain, leveraging FBC AMI data to estimate unbilled power, improve the assignment of costs to customers, inform rate design and power purchases, and identify system losses more accurately. FBC expects to realize total O&M savings of approximately $0.125 million by the end of 2025.

Enterprise Analytics will also support streamlining existing reporting processes for financial and management reporting. Currently, the reporting processes work well with clearly defined requirements and processes but rely on manual effort. Enterprise Analytics provides an automated solution that reduces the effort required to generate reports, with expected productivity gains. This automation is achieved through the use of a data model to aggregate data sources and a reporting tool to allow for self-service. FBC plans to implement two or three automated reporting solutions in 2023.

4. **Robotics Process Automation (RPA):** This is an efficiency initiative using automation software to alleviate repetitive and simple manual tasks. With the rising volume of manual tasks performed for operational work, such as financial transactions or project closeout activities, departments within FortisBC are challenged.

   In 2022, the Company initiated the first phase of RPA implementation, working to automate several repetitive and manual processes in the Finance department and one in the Engineering department. The processes chosen were small, low-risk opportunities to introduce RPA to the organization. The first Finance process went into production in mid-2022 with others following throughout the remainder of the year. The Engineering process went into production in the first half of 2023. The automation of the Finance processes has resulted in:

   - faster and more timely processing of monthly journal entries, allowing for earlier and increased analysis and review time;
   - a shift in how time is spent, moving from data-entry-style rote work on several processes;
   - a reduction in time spent reperforming work due to human errors; and
   - an overall reduction in time spent on certain processes.

   The operational efficiency value gained by RPA is incremental but compounds as more processes are automated.

   In 2023, the Company is adding to automation within the Finance area as well as evaluating opportunities in other business areas to grow the RPA initiative. Additional process opportunities include populating Financial and Internal Audit reports and filings, application of customer bill payments, net-metering amendment of Electric bills, processing of rebate applications, onboarding of new users within IS systems, and automating manual document control processes within Engineering projects. A

governance structure will also be established to prioritize and control RPA implementations, as well as ensuring that RPA implementations align with the overall business strategy and objectives, and that the necessary resources and support are available for successful implementation and ongoing maintenance of the automated processes. FBC expects to realize total O&M savings of approximately $0.025 million by the end of 2024.

5. **Paperless Billing Customer Campaigns:** This initiative focuses on working with customers to encourage the switch to paperless billing. In addition to the convenience for customers of receiving their bill electronically and the environmental considerations of less paper and physical transport of the bills, an increased percentage of customers making the switch to paperless billing results in ongoing printing and postage cost savings. At the start of 2022, FBC had approximately 77,000 customers choosing paperless billing as their preferred bill delivery method. Following the success of several internal programs that encouraged employees to highlight this option with customers and including an external social media campaign that resulted in donations to food banks in need, FBC achieved an increase of approximately 6,500 customers choosing this option in 2022. This increase equates to approximately $0.05 million in printing and postage cost savings for FBC in 2022 as compared to 2021.[1]

6. **Other Initiatives:** FortisBC is continuously looking for efficiencies and improvements in its activities, in a larger scale as the initiatives described above, or at a smaller scale as described in the following initiatives.

Mobile enabling applications: FortisBC has different initiatives to digitize forms and provide the ability to complete these forms on mobile devices in the field or office. Digitizing these forms supports effective data capture, and improves consistency, reliability, comprehension of data collected and reduces risk of manual errors. Additionally, it reduces the administrative efforts that occur with paper forms. FortisBC expects to realize minor savings by the end of 2023, and additional savings will be realized as FortisBC continues to mobile-enable and digitize other paper forms.

Automated patching: FortisBC has started taking advantage of technologies for automated patching. Moving to automated patching has streamlined the patching process for several applications in the FortisBC environment. With automated patching, the process can be scheduled to run during a more appropriate business outage window with no user involvement required. Repetitive tasks can be automated, eliminating human error, increasing productivity, and decreasing administrative costs. FortisBC expects to realize minor O&M savings by the end of 2023 with increased patch cadence and accuracy. Additional time savings will be seen as more systems transition to automated patching.

[1] Calculation is a high-level estimate based on the incremental monthly paperless billing growth at an average savings of approximately $1.21 per bill.

Other IS Initiatives: A High Availability (HA) operating environment enables applications to continue to operate even if one of the information technology components fails, and to ensure continuous operation and uptime. HA allows IS to schedule upgrades, patches, and release tasks during business hours, ultimately improving business operations and reducing overtime costs. IS has also expanded the use of automated testing. The expanded use of automation allows for an increase in system testing and improved product quality with a decrease in proportionate need for additional testing resources. Automation is expected to continue to expand in use at FortisBC in the future.

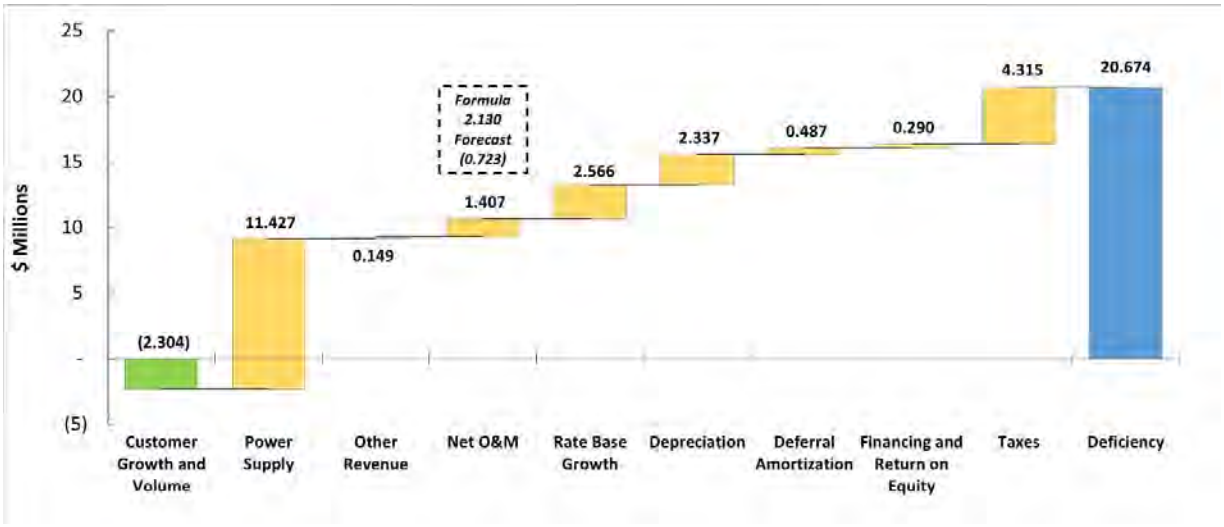
Customer Service Initiatives: Ongoing smaller initiatives include automating the tracking of collections and refund cases, improving training materials for high volume call types, and introducing emails for electric collections customers. While on a smaller scale, these initiatives contribute to improving customers' experience with FortisBC and the Company maintaining a focus on being cost effective in its use of resources.

1.5 REVENUE REQUIREMENT AND RATE CHANGES FOR 2024

The revenue requirement components set out in the Application result in an effective rate increase of 4.83 percent for 2024 compared to 2023. The effective rate increase results from a revenue deficiency of $20.674 million.

The following chart summarizes the items that contribute to the 2024 revenue deficiency. The chart shows each item that increases the deficiency in yellow and each item that decreases the deficiency in green. The 2024 deficiency of $20.674 million is then the sum of all of the previous bars and is shown at the end of the chart in blue.

Figure 1-1: 2024 Revenue Deficiency ($ millions)



Each of the categories is discussed briefly below.

1.5.1 Customer Growth and Volume Forecast (Section 3)

For 2024, FBC forecasts the net load to decrease by approximately 1 GWh when compared to 2023 Approved, with the forecast increases from the wholesale and commercial customer classes completely offset by decreases in the residential, industrial, and irrigation customer classes. Despite the slight decrease in net load of 1 GWh forecast for 2024, FBC is forecasting a small increase in revenue of $2.304 million, primarily due to the forecast increase in load from the wholesale customers as well as a forecast increase in residential and commercial customer counts (resulting in a small increase in the fixed monthly/bi-monthly customer charges). FBC's 2024 Forecast revenue at 2023 approved rates is $428.377 million.

1.5.2 Power Supply (Section 4)

FBC forecasts an increase in power supply of $11.427 million in 2024 compared to 2023 Approved. This increase is primarily due to the higher purchase rates for power from the market and contracted producers (included as part of the power purchase expense), followed by smaller increases in the BC Hydro Power Purchase Agreement (PPA), wheeling expenses, and water fees.

1.5.3 Other Revenue (Section 5)

Other Revenue is forecast to increase the 2024 revenue deficiency by $0.149 million, primarily due to reduced contract revenue and transmission access revenue.

1.5.4 Operations and Maintenance (O&M) Expense (Section 6)

FBC establishes the majority of its O&M expense by formula during the MRP term. The O&M formula incorporates a net inflation factor of 3.580 percent, which is inclusive of a productivity improvement factor (X-Factor) of 0.5 percent, and uses a forecast of the change in average customers.[2] The 2024 Formula O&M net of capitalized overhead has increased by $2.130 million[3] when compared to the 2023 Formula O&M, which is partially offset by a decrease in net O&M forecast outside of the formula by approximately $0.723 million,[4] primarily due to a decrease in pension and OPEB expense. Overall, the 2024 increase in total O&M expense net of capitalized overhead is $1.407 million (2.3 percent).

1.5.5 Rate Base Growth (Section 7)

The 2024 rate base is forecast to increase by approximately $39.492 million when compared to the 2023 Approved rate base, resulting in an increase to the 2024 Forecast earned return and the 2024 revenue deficiency of approximately $2.566 million. The increase in rate base is primarily due to the mid-year impact of FBC's 2024 regular capital additions to plant, followed by, to a lesser extent, the full-year impact of FBC's major capital project additions, including the Kelowna

[2] Modified by 75 percent.
[3] Increase in gross formula O&M of $2.506 million (3.6 percent) compared to 2023 Approved.
[4] Decrease in gross forecast O&M of $0.850 million (-36.2 percent) compared to 2023 Approved.

Bulk Transformer Additions (KBTA) project and the Corra Linn Dam Spillway Gates Replacement project.

1.5.6 Depreciation (Section 7)

Depreciation expense in 2024 is forecast to increase the 2024 revenue deficiency by $2.579 million compared to 2023 Approved. This increase is due to the forecast increase in rate base discussed above. The increase in depreciation expense is partially offset by approximately $0.242 million of CIAC from net additions, resulting in a net increase of $2.337 million in depreciation expense.

1.5.7 Amortization of Deferral Accounts (Section 7 and Section 12)

Amortization of deferral accounts in 2024 is forecast to increase by $0.487 million, primarily due to a reduction in the credit amortization related to the 2020-2024 Flow-through non-rate base deferral account. This increase in amortization expense due to the reduced credit amortization from the Flow-through deferral account is partially offset by an increase in credit amortization from the MRP Earnings Sharing deferral account as well as the amortization of credit balances in the Princeton Office Disposition deferral account, the proposed BC Cost of Living Credit deferral account, and the proposed PST Rebate on Select Machinery and Equipment deferral account.

1.5.8 Financing and Return on Equity (Section 8)

Financing and Return on Equity (ROE) increased the 2024 deficiency by $0.290 million through changes in financing rates, the ratio of long-term debt versus short-term debt, and changes in rate base.

For 2024, FBC is forecasting a short-term debt rate of 5.21 percent, which is an increase from the short-term debt rate embedded in the 2023 Approved revenue requirement of 4.24 percent. Overall, FBC's revenue deficiency is increased by $0.346 million from financing rate changes, which is offset by $0.056 million from the ratio change between long-term and short-term debt.

In calculating its 2024 revenue deficiency, FBC has utilized its currently approved capital structure and return on equity (ROE) of 40 percent and 9.15 percent, respectively, as approved by Orders G-129-16 and G-47-14. As explained in Section 8.1, FBC's ROE is set at a premium of 40 basis points over the benchmark ROE, which is the ROE approved for FEI. FBC is currently awaiting a decision on Stage 1 of the BCUC-initiated Generic Cost of Capital (GCOC) proceeding which is expected to be issued in the upcoming months. FBC will provide an update to its rate calculations as part of an Evidentiary Update subsequent to the GCOC decision being issued.

1.5.9 Taxes (Section 9)

FBC's 2024 property taxes are forecast to increase by 1.7 percent or $0.313 million from 2023 Approved. The increase is primarily due to changes in tax rates and increases in assessed values.

There has been no change in the income tax rate of 27 percent from 2023. Taxes are forecast to increase in 2024 by $4.002 million. The largest driver of the increase in 2024 is the lower income tax deductible through capital cost allowance (CCA), which led to an increase in income tax expense by approximately $2.849 million. The lower CCA is partly due to reduced undepreciated capital cost (UCC) additions in higher rate CCA classes in the 2024 Forecast compared to 2023 Approved, and partly due to the phase-out of Canada's Accelerated Investment Incentive starting from 2024 (i.e., enhanced 50 percent first-year allowance to be phased out in 2024). Income tax is also higher as a result of higher 2024 Forecast earned return and depreciation expense, which is partially offset by lower amortization of deferred charges.

1.6 SERVICE QUALITY INDICATORS (SECTION 13)

FBC reports on its 2022 and June 2023 year-to-date SQI results in Section 13. In 2022, for the eight SQIs with benchmarks, six met or were better than the benchmark, with the First Contact Resolution SQI better than the threshold and the Telephone Service Factor (Non-Emergency) SQI lower than the threshold. For the four SQIs that are informational only, the Average Speed of Answer results were higher due to the same challenges impacting the Telephone Service Factor (Non-Emergency), while performance in 2022 for the other three informational metrics generally remained at a level consistent with prior years. In 2023 to date, performance for the metrics with benchmarks is trending towards meeting the benchmark or the threshold.

2. FORMULA DRIVERS

2.1 INTRODUCTION AND OVERVIEW

This section provides the calculation of the Inflation Factor (or I-Factor) and Growth Factor used for calculating the 2024 O&M amounts according to the MRP formula.

In the MRP Decision and Order G-166-20, the BCUC approved an I-Factor using the actual CPI-BC and BC-AWE indices from the previous year and a labour weighting based on the most recent completed year of actuals.[5]

The MRP Decision approved the use of a forecast of growth[6] to determine formula O&M and determined that a growth factor multiplier of 75 percent for formula O&M was appropriate.

The Inflation Factor and Growth Factor calculations utilize the above-described inputs and determinations. For 2024, FBC has used July 2021 through June 2023 inflation data for the 2024 revenue requirement calculations, using the Statistics Canada tables included in Appendix A1 of the Application.

Section 2.2 below explains how FBC determined the 2024 Inflation Factor based on prior years' BC-CPI and BC-AWE, and Section 2.3 below explains how FBC determined the average customer count. Both the inflation factor and the average customer count are used to calculate the formula O&M discussed in Section 6.

2.2 INFLATION FACTOR CALCULATION SUMMARY

In the MRP Decision, the BCUC approved an I-Factor using the actual CPI-BC and BC-AWE indices from the previous year and the actual labour weighting based on the most recent completed year of actuals. FBC uses inflation data from July through June and Statistics Canada Table 18-10-0004-01 for CPI-BC and Table 14-10-0223-01 to determine AWE-BC. The supporting Statistics Canada tables are provided in Appendix A1. The latest available month of April 2023 for AWE-BC has been used as a placeholder, as results to June 2023 have not been released by Statistics Canada. Once results for these periods are available, this placeholder will be replaced with actuals and included in an Evidentiary Update or Compliance Filing.

As shown in Table 2-1 below, the I-Factor has been calculated utilizing actual CPI-BC and AWE-BC data. Applying the actual 2022 labour weighting of 57 percent, the calculation of the 2024 I-Factor is (6.031 percent x 43 percent) + (2.609 percent x 57 percent) = 4.080 percent.

[5] FBC's most recent year of completed actuals is 2022 so that ratio has been used for the 2024 I-Factor calculation.
[6] Forecast of average customers for Formula O&M, including a true-up to actual customers in the following years.

Table 2-1: I-Factor Calculation

Line No.	Date	*Table: 18-10-0004-01* BC CPI index	*Table: 14-10-0223-01* BC AWE $	12 Mth Average CPI index	12 Mth Average AWE $	CPI %	AWE %	Last Completed Year Non Labour %	Last Completed Year Labour %	I-Factor %	MRP Year
1	Jul-2021	136.7	1,143.76								
2	Aug-2021	137.0	1,143.96								
3	Sep-2021	137.2	1,142.37								
4	Oct-2021	137.9	1,140.94								
5	Nov-2021	138.1	1,129.51								
6	Dec-2021	138.0	1,132.93								
7	Jan-2022	139.4	1,155.32								
8	Feb-2022	140.4	1,153.57								
9	Mar-2022	143.0	1,161.00								
10	Apr-2022	144.2	1,164.51								
11	May-2022	146.1	1,159.89								
12	Jun-2022	146.5	1,167.14	140.4	1,149.58						
13	Jul-2022	147.6	1,162.26								
14	Aug-2022	147.0	1,171.52								
15	Sep-2022	147.8	1,171.94								
16	Oct-2022	148.6	1,174.29								
17	Nov-2022	148.1	1,176.97								
18	Dec-2022	147.1	1,153.31								
19	Jan-2023	148.1	1,180.04								
20	Feb-2023	149.1	1,175.83								
21	Mar-2023	149.7	1,191.20								
22	Apr-2023	150.4	1,199.14								
23	May-2023	151.0	1,199.14								
24	Jun-2023	151.6	1,199.14	148.8	1,179.57	6.031%	2.609%	43%	57%	4.080%	2024

2.3 GROWTH FACTOR CALCULATION SUMMARY

As noted above, the BCUC approved the use of a forecast of average customers with a 75 percent modifier to determine formula O&M.

The calculation of average customers used to determine 2024 Formula O&M is summarized in the table below. The growth factor is applied to the unit cost O&M (UCOM), which was calculated based on 2019 average customers of 139,916 (shown on line 21 under year 2020 or line 28 in Table 2-2 below). Starting with this 2019 average customer count, the calculation adds 75 percent of the cumulative average of actual/forecast customer growth during the MRP term from 2020 to 2024 (shown on line 26 in Table 2-2 below) to determine the average customers for rate setting (shown on line 29 of Table 2-2 below).

Table 2-2: Calculation of 2024 Average Customer (AC) Growth Factor

Line No.	Date	Actual 2020	Actual 2021	Actual 2022	Projected 2023	Forecast 2024	Total for 2024 Rate Setting	Reference
1	Prior Year Ending Customer Count	141,027	143,714	145,830	148,435	150,761		Appendix A2 - Section 3.1 Customers
2								
3	Additions:							
4	January	292	257	226	162	192		
5	February	174	89	194	189	194		
6	March	8	123	122	192	191		
7	April	110	113	178	169	193		
8	May	173	319	(25)	277	185		
9	June	172	116	353	121	192		
10	July	522	308	352	245	193		
11	August	129	187	204	193	191		
12	September	83	136	155	195	193		
13	October	545	132	261	197	195		
14	November	234	217	319	190	188		
15	December	245	119	266	197	195		
16	Total Additions	2,687	2,116	2,605	2,326	2,302		Appendix A2 - Section 3.2 Customer Additions
17	12-month Weighted Average Additions	1,294	1,163	1,282	1,242	1,245		
18								
19	Current Year Ending Customer Count	143,714	145,830	148,435	150,761	153,063		Line 1 + Line 16; Appendix A2 - Section 3.1 Customers
20								
21	Actual/Projected Prior Year Average Customers	139,916	142,321	144,877	147,112	149,677		2020: G-42-21; Sch 3, Line 13; 2021-2024: Prior Year, Line 22
22	Average Customers for the Year	142,321	144,877	147,112	149,677	152,006		Line 1 + Line 17
23	Change in Average Customers	2,405	2,556	2,235	2,565	2,329	**12,090**	Sum of Annual Change in Average Customers on Line 23
24								
25	Growth Factor Multiplier						**75%**	G-166-20
26	Change in Average Customers for Rate Setting Purposes						**9,068**	Line 25 x Line 23
27								
28	Average Customers Used to Determine the Starting UCOM						**139,916**	Line 21, Yr 2020
29	**Average Customer Forecast for Rate Setting**						**148,984**	Line 28 + Line 26
30								
31	2022 Approved Average Customers for Rate Setting			145,378				2022: G-374-21; Sch 3, Line 22
32	2022 Actual Average Customers for Rate Setting			145,313				Line 21 (2020) + Sum of Line 23 (2020, 2021, 2022) x 0.75
33	**2022 True Up**			**(65)**				Line 32 - Line 31

2.4 INFLATION AND GROWTH CALCULATION SUMMARY

A summary of the factors used to determine formula O&M for 2024 is provided in Table 2-3, including the I-Factor calculated in Section 2.2, the approved X-Factor of 0.5 percent, and the forecast of average customers incorporating the growth factor multiplier determined in Section 2.3.

Table 2-3: Summary of Formula Drivers

Line No.	Description	2024	Reference
1	CPI	6.031%	Table 2-1, Line 24
2	AWE	2.609%	Table 2-1, Line 24
3			
4	Non Labour	43%	Table 2-1, Line 24
5	Labour	57%	Table 2-1, Line 24
6			
7	CPI/AWE Inflation	4.080%	(Line 1 x Line 4) + (Line 2 x Line 5)
8			
9	Productivity Factor	-0.500%	Order G-166-20
10			
11	Net Inflation Factor	3.580%	Line 7 + Line 9
12			
13	Average Customer Forecast for Formula O&M purposes	148,984	Table 2-2, Line 29

In summary, the Net Inflation Factor for 2024 is 3.580 percent and formula O&M for 2024 is determined using average customers of 148,984.

3. LOAD FORECAST AND REVENUE AT EXISTING RATES

3.1 INTRODUCTION AND OVERVIEW

This section describes FBC's forecast of gross system load. The gross system load is a combination of residential, commercial, wholesale, industrial, lighting and irrigation loads, system losses and company use. The forecast of gross system load includes the impacts of forecast load savings which include Demand Side Management (DSM) savings. These savings are further explained in Section 3.3 – Demand Side Management Savings.

FBC is forecasting a decrease in consumption in the 2024 Forecast (2024F) compared to the 2023 Approved. The 2024F gross load is forecast to be approximately 3,773 GWh, which is 2 GWh lower than the 2023 Approved gross load. The decrease is primarily due to a reduction in loads from the residential, industrial, and irrigation classes, which almost completely offsets the increase in loads from the wholesale and commercial customers. Despite the decrease in the 2024 Forecast gross load, FBC is forecasting the 2024 revenue to be $428.377 million, which is an increase of $2.304 million when calculated based on the 2023 Approved rates for each customer class. The increase in revenue for 2024 is primarily due to the forecast increase in load from the wholesale customers, as well as an increase in recoveries from the fixed monthly/bimonthly customer charges resulting from the forecast increase in customer counts in the residential and commercial classes.

FBC has provided further information supporting its load forecast in Appendix A of the Application.

3.2 OVERVIEW OF FORECAST METHODS

Consistent with the forecasting method followed by FBC in previous years, the load forecast relies on the following components:

- the residential and commercial customer count forecast;
- the residential use per customer (UPC) forecast;
- the commercial, lighting and irrigation load forecast; and
- the industrial and wholesale survey forecast.

The load forecast for residential customers is based on forecasts for the number of customers and UPC rates. Specifically, the UPC forecast is multiplied by the corresponding forecast of the number of annual average customers to derive the residential load forecast. The commercial load forecast is based on a regression against the Conference Board of Canada (CBOC) Gross Domestic Product (GDP) forecast, the lighting forecast uses the prior year's actual load, and the irrigation forecast uses a five-year historical average. Finally, wholesale and industrial forecasts are primarily based on customer-specific survey results.

More detail on FBC's forecasting methods can be found in Appendix A of this filing.

The following sections set out the results of the load forecast. In the figures provided in the load forecast sections, the following three time periods are shown:

- Actual Years: Actual years are those for which actual data exists for the full calendar year. For this Annual Review the latest calendar year for which full actual data exists is the 2022 calendar year.

- Seed Year: The Seed Year is the year prior to the first forecast year. The Seed Year is forecast based on the latest years of actual data available,[7] and will be different than the original forecast for that year in the previous filing. For example, for this Application the Seed Year is 2023 (2023S) and the Seed Year forecast is based on the latest actual years, including 2022. As such, the 2023 Seed Year forecast in this Application will differ from the 2023 Forecast presented in the Annual Review for 2023 Rates, for which 2022 actual data was not available.

- Forecast Year: This is the year or years for which the forecast is being developed. This can be one year (in the case of the Annual Review) or a range of two or more years depending on the filing. In this Application, the forecast year is 2024 (2024F).

- Also included in the figures in this section is the prior year's forecast (shown as the green Approved lines in the figures below), as presented in the Annual Review for 2023 Rates.

FBC acquired the utility assets and customers of the City of Kelowna's electric utility effective March 31, 2013, resulting in an increase in direct customers and changes in the composition of customers and sales load by class, which are reflected in the data and figures in this section.

3.3 DEMAND SIDE MANAGEMENT SAVINGS

FBC forecasts the DSM savings that are incremental to the DSM savings that are already embedded in historical loads up to and including 2022.

The DSM savings forecast is deducted from the before-savings forecast for all customer classes. All forecast values in the sections below are shown after being reduced by DSM savings unless explicitly stated otherwise.

The forecast incremental DSM savings for 2024 are summarized in Table 3-1 below, and are the forecast savings incremental to the savings embedded in the historical loads. Historical DSM savings can be found in Appendix A2.

[7] FBC's load forecast is developed using only complete years of historical data. FBC requires the complete year of load data in order to validate it, including the review of and potential adjustments to unbilled energy. For this reason, partial year data is not used in forecasting.

Table 3-1: Forecast Incremental 2024 DSM Savings (GWh)

Line No.	Description	DSM 2024
1	Residential	(9.1)
2	Commercial	(22.3)
3	Wholesale	(7.6)
4	Industrial	(13.5)
5	Lighting	(0.2)
6	Irrigation	(0.2)
7	Net	(52.9)
8	Losses	(4.3)
9	Gross Load	(57.2)

3.4 LOAD FORECAST

FBC's total load consists of the weather normalized residential and wholesale load and the actual commercial,[8] industrial, lighting and irrigation load. In aggregate, the absolute load forecast variance in 2022 was 4.7 percent, which was primarily due to higher industrial loads and more residential customers coming onto the system than forecast. As shown in Figure 3-1 below, the total load, net of losses, is forecast to be 3,473.9 GWh in 2024F, which is 1.8 GWh less than 2023S and 1.4 GWh less than 2023 Approved.

[8] Commercial loads are tested for weather sensitivity each year. For 2024, there is a low correlation with weather and as a result, the actual historic commercial loads are used in the preparation of Figures 3-1 and 3-5. Please refer to Section 1.1 of Appendix A-3 for further detail.

Figure 3-1: Total Net Load (GWh)

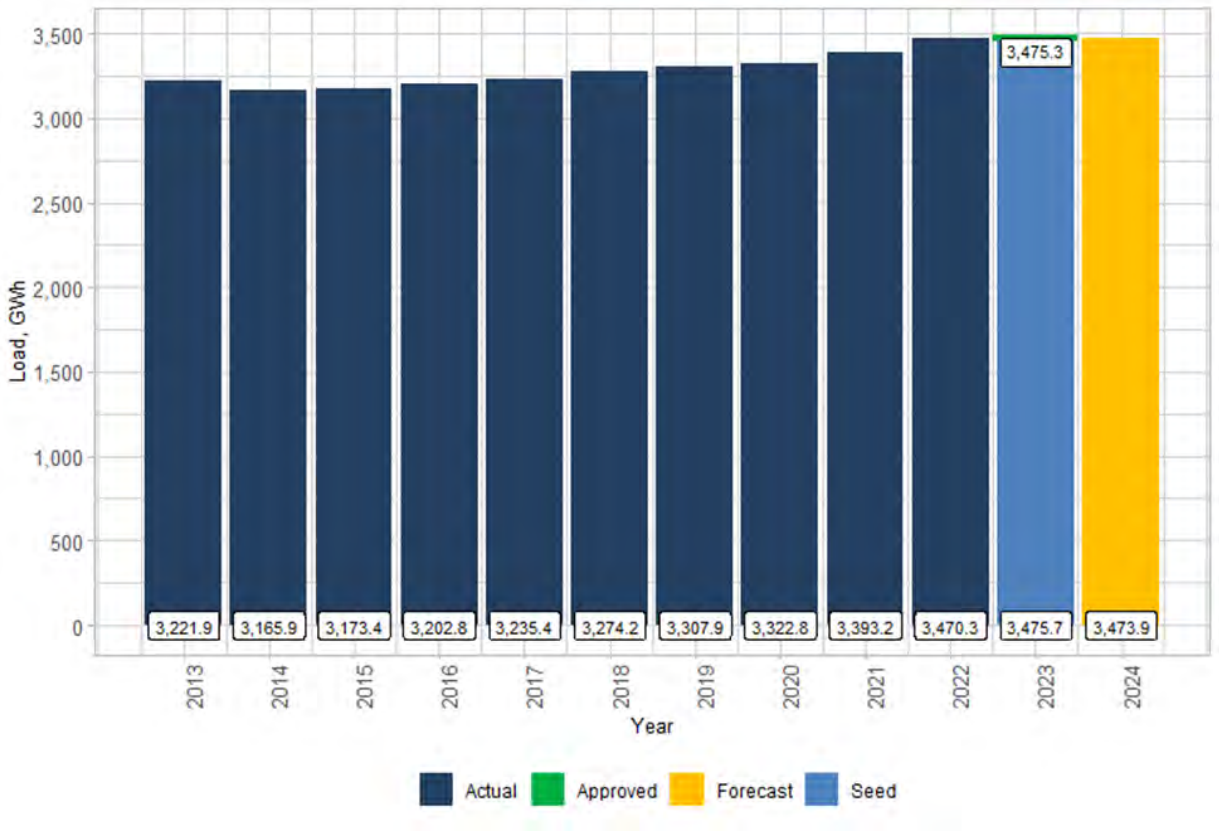


Table 3-2 below shows the normalized after-savings gross load by customer class as well as the system peak. For 2024F, the residential customer class is forecast to account for 34 percent of the normalized after-savings gross load.

Table 3-2: After-Savings Gross Load and System Peak[9]

Line No.	Description	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023S	2024F
	Energy (GWh)												
1	Residential	1,352.9	1,296.5	1,298.1	1,295.6	1,320.5	1,312.6	1,266.1	1,346.8	1,330.3	1,320.4	1,307.6	1,298.9
2	Commercial	788.2	865.7	853.2	901.4	920.4	922.0	933.9	917.2	971.4	969.1	967.5	974.2
3	Wholesale	675.2	567.1	580.5	574.4	574.1	584.7	566.0	569.5	565.8	575.5	590.7	589.8
4	Industrial	352.3	380.9	379.7	373.4	362.6	402.7	494.9	441.2	472.3	558.5	562.1	563.5
5	Lighting	13.5	15.6	15.9	15.9	15.9	13.2	11.0	10.8	9.7	9.3	9.2	9.1
6	Irrigation	39.7	40.0	46.0	42.1	41.9	39.0	36.0	37.3	43.6	37.6	38.6	38.5
7	Net Load	3,221.9	3,165.9	3,173.4	3,202.8	3,235.4	3,274.2	3,307.9	3,322.8	3,393.2	3,470.3	3,475.7	3,473.9
8	Losses & Company Use	278.1	270.1	272.4	273.8	282.3	285.1	286.9	287.9	299.7	314.6	298.9	298.7
9	Gross Load	3,500.0	3,436.0	3,445.8	3,476.6	3,517.7	3,559.4	3,594.8	3,610.8	3,692.8	3,784.8	3,774.5	3,772.7
10													
11	System Peak (MW)												
12	Winter Peak	698.1	692.6	685.0	754.7	713.6	682.2	732.4	730.8	684.8	734.3	783.4	785.0
13	Summer Peak	600.4	619.5	611.0	593.0	604.8	630.9	639.4	666.2	652.9	689.1	696.2	697.3

[9] The system peaks shown on Lines 12 and 13 are weather-normalized winter and summer peaks. Refer to Section 3.4.8 for further details.

The residential, commercial, wholesale, industrial, lighting, irrigation, loss load and the winter and summer peak demand forecasts are provided separately in the following subsections.

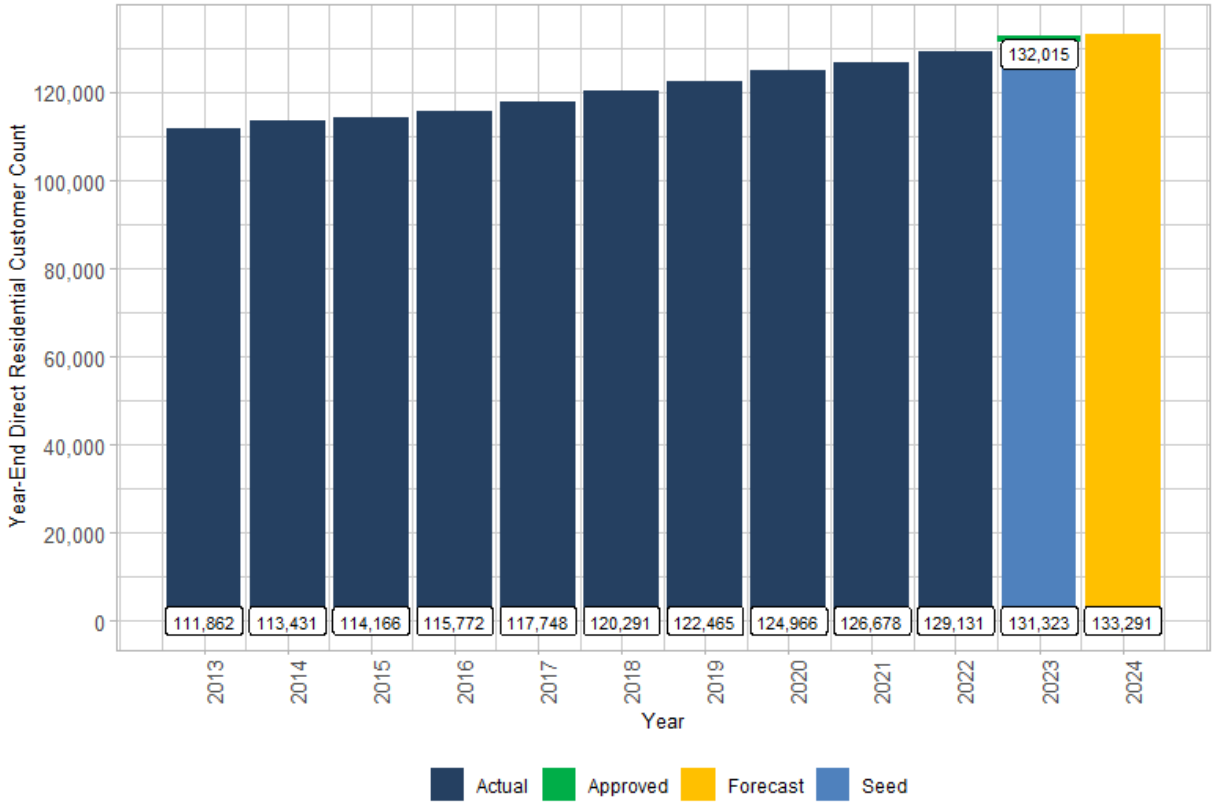
3.4.1 Residential

3.4.1.1 Residential Customers

Forecast residential customer counts are determined by a regression of the year-end customer accounts against population in the FBC direct service area. The population forecast for the FBC service area is provided by a BC Statistics report produced for FBC.

Figure 3-2 shows the year-end direct residential customer count for FBC.

Figure 3-2: Year-End Direct Residential Customer Count



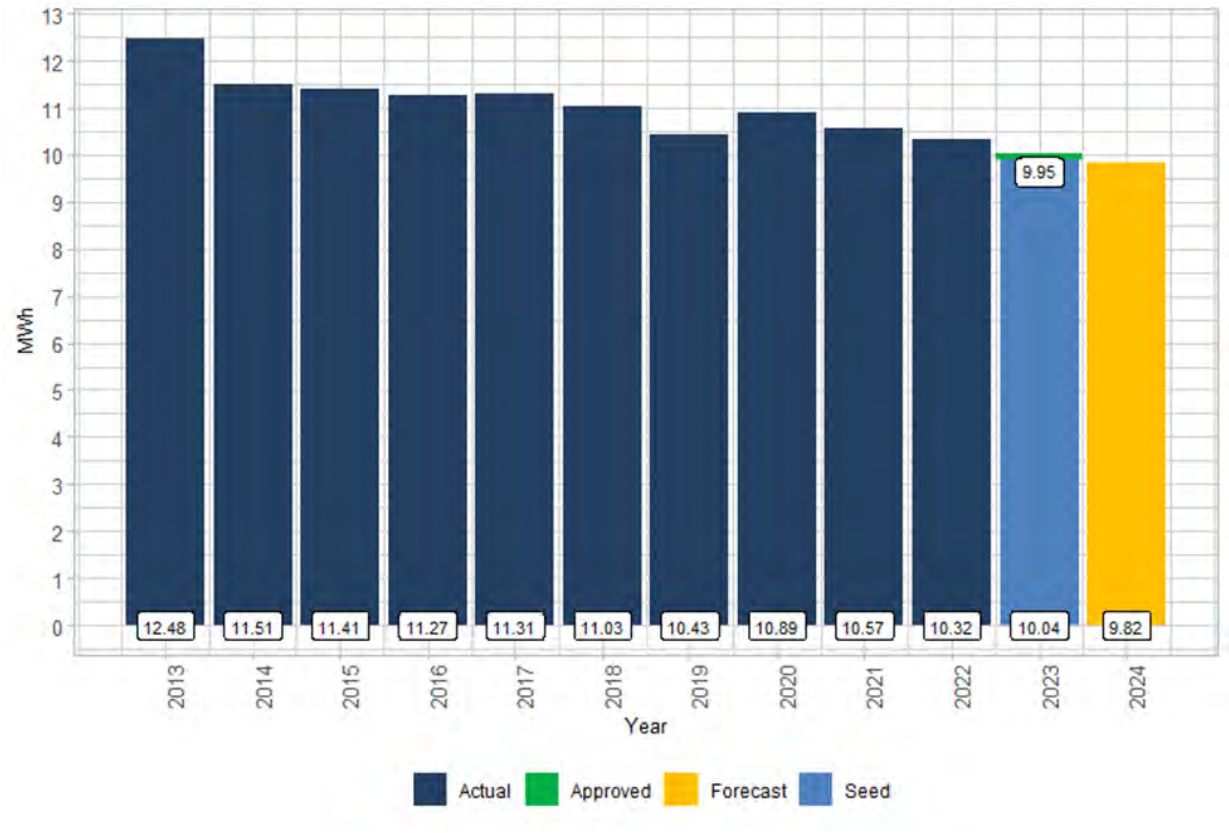
3.4.1.2 Residential UPC

Normalized historical UPCs are obtained by dividing the weather-normalized residential load by the average customer count in each year. The before-savings UPC is forecast by applying a 10-year trend to the normalized historical UPCs. The before-savings UPC forecast is then multiplied by the forecast average customer count to derive the before-savings load forecast. DSM savings, which are incremental to the savings embedded in the historical data to 2022, are then deducted

from the before-savings load forecast to determine the after-savings load forecast. The after-savings UPC forecast is then calculated by dividing the after-savings load forecast by the average customer count.

As shown in Figure 3-3 below, the residential after-savings UPC is forecast to decrease by 0.22 MWh in 2024F from 2023S and decrease by 0.13 MWh from 2023 Approved.

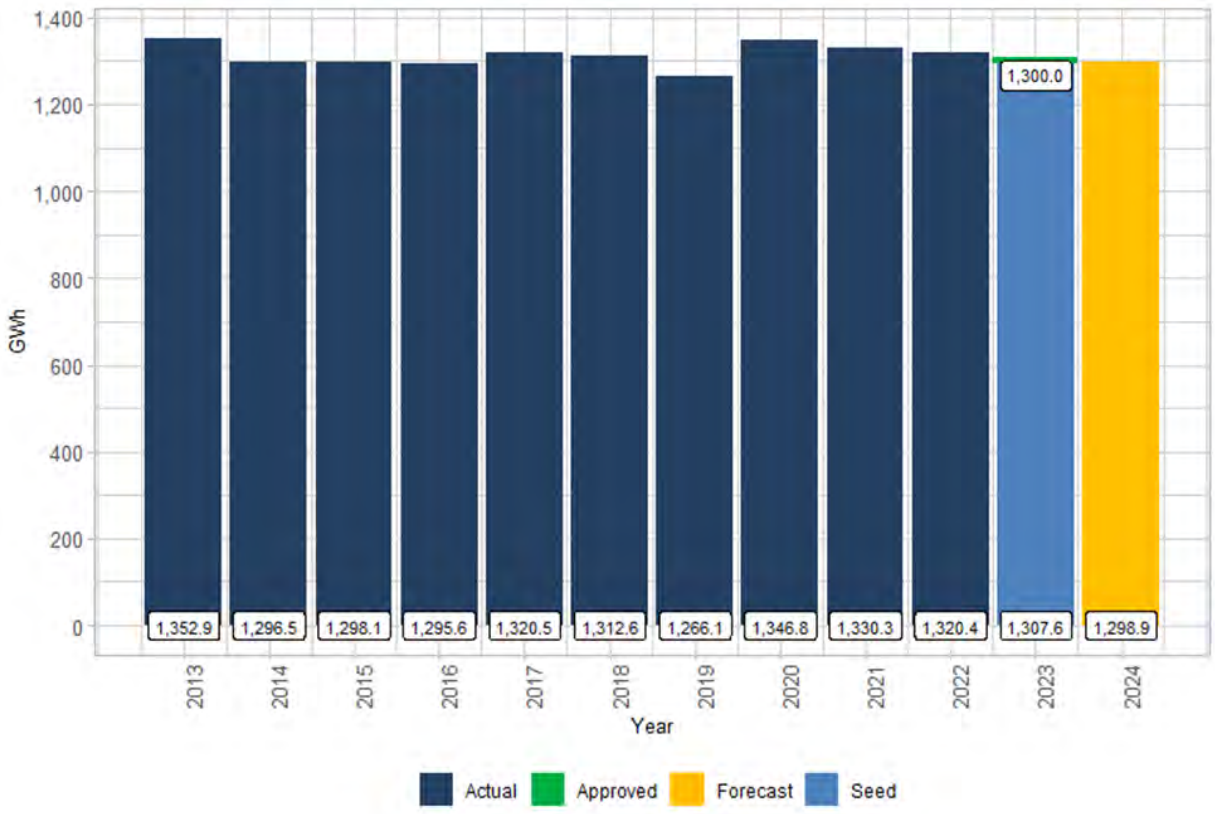
Figure 3-3: Normalized After-Savings Residential UPC (MWh)



3.4.1.3 Residential Load

Consistent with past practice, the total before-savings load for the residential class is the product of the average annual residential customer count multiplied by the residential UPC. The after-savings load is produced by taking the before-savings load and then subtracting DSM savings. As shown in Figure 3-4 below, residential after-DSM savings load is forecast to decrease by 8.7 GWh in 2024F from 2023S and decrease by 1.1 GWh from 2023 Approved levels.

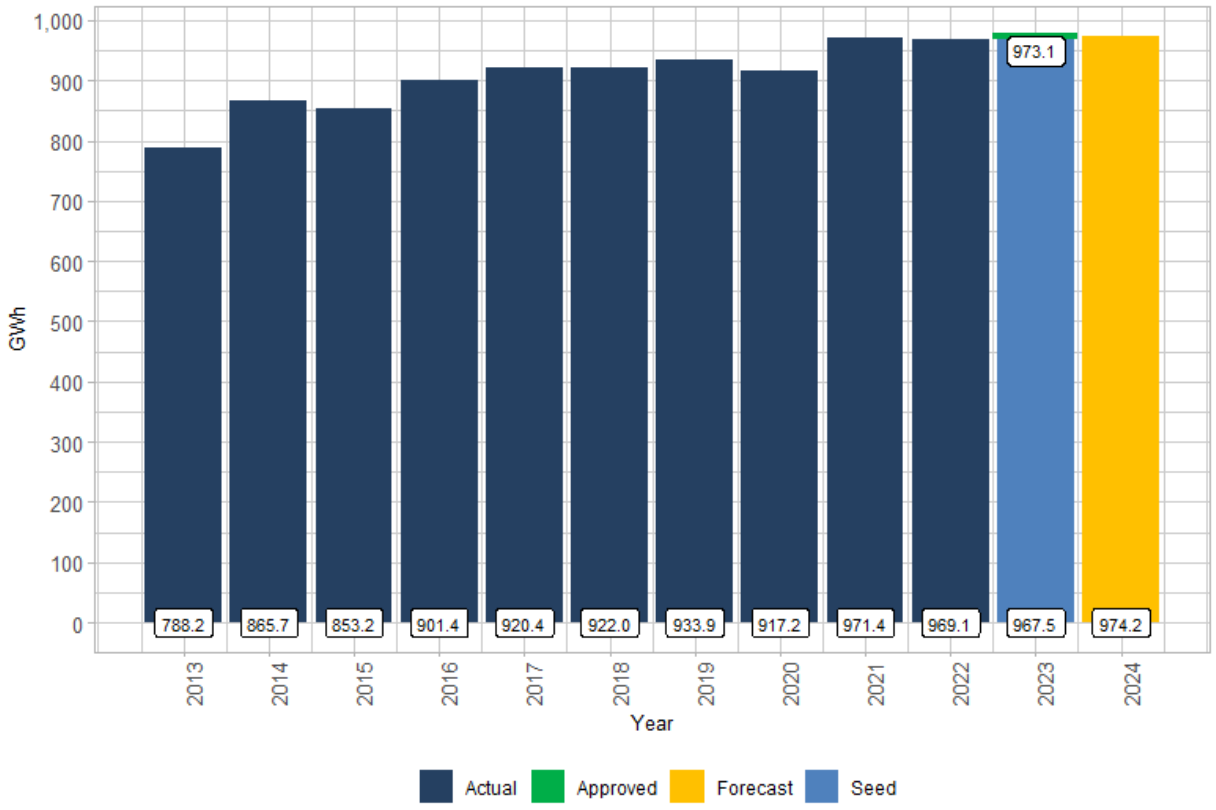
Figure 3-4: Normalized After-Savings Residential Load (GWh)



3.4.2 Commercial

The commercial class load and customer forecasts are based on regressions against the provincial GDP forecast obtained from the CBOC. The load for Electric Vehicle Direct Current Fast Chargers (EV DCFC) serviced by FBC are then added to 2023S and 2024F and account for a less than 1 GWh increase in both 2023S and 2024F. As shown in Figure 3-5 below, commercial after-savings load is forecast to increase by 6.7 GWh in 2024F from 2023S and increase by 1.1 GWh in 2024F from 2023 Approved.

Figure 3-5: After-Savings Commercial Load (GWh)



3.4.3 Wholesale

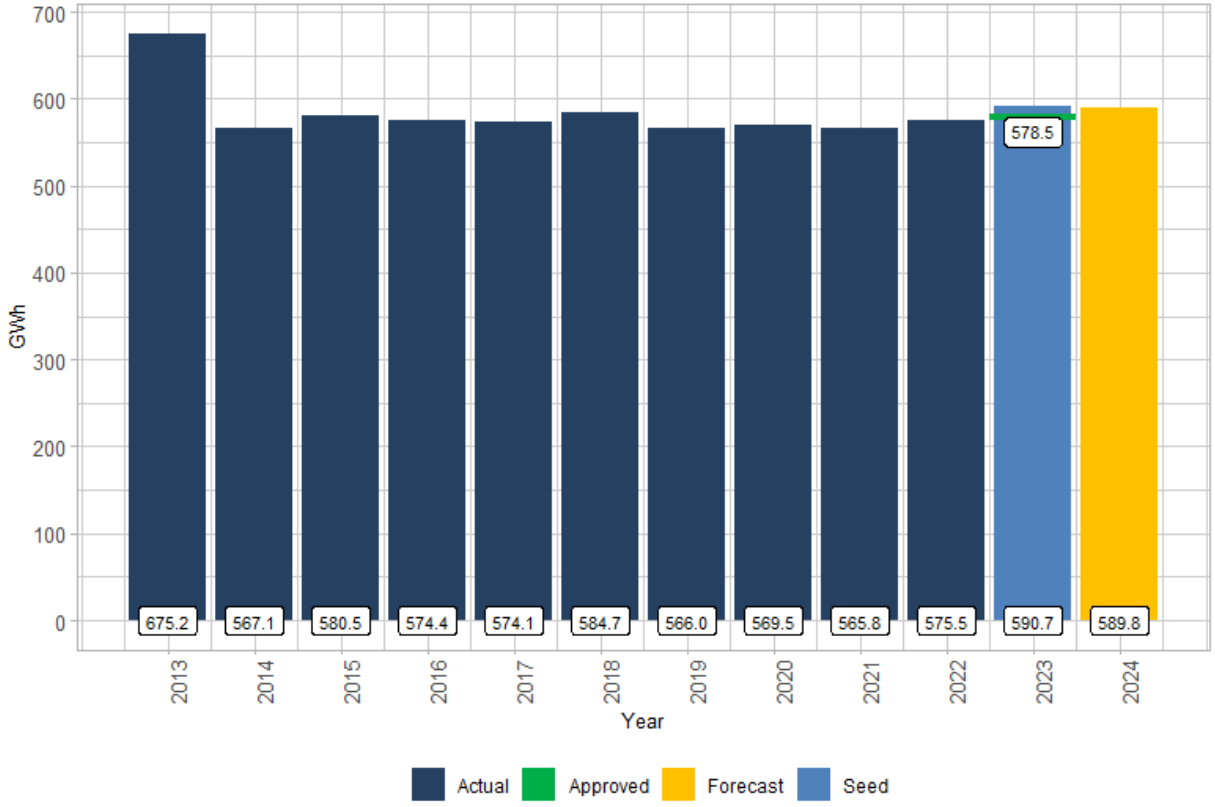
FBC sells wholesale power to municipalities for service to certain customers within its service territory that own and operate their own electrical distribution systems, and to BC Hydro. The wholesale customers' load composition is a combination of residential, commercial, industrial and lighting.

Consistent with past practice, the wholesale class is forecast using survey information from each of the individual wholesale customers, as the individual wholesale customers are best able to forecast their future load growth. For 2024, all wholesale customers responded with their load forecasts.

Consistent with the approach taken when preparing last year's wholesale load forecast (i.e., the load forecast presented in the Annual Review for 2023 Rates), FBC once again invited each wholesale customer to a workshop. In April 2023, workshops were completed with both the City of Penticton and the City of Nelson. The remainder of the wholesale customers declined the invitation. FBC continues to find these information sharing sessions valuable and plans to continue them in the future.

As shown in Figure 3-6 below, after-savings wholesale load is forecast to decrease by 0.9 GWh in 2024F from 2023S and increase by 11.3 GWh in 2024F from 2023 Approved.

Figure 3-6: Normalized After-Savings Wholesale Load (GWh)



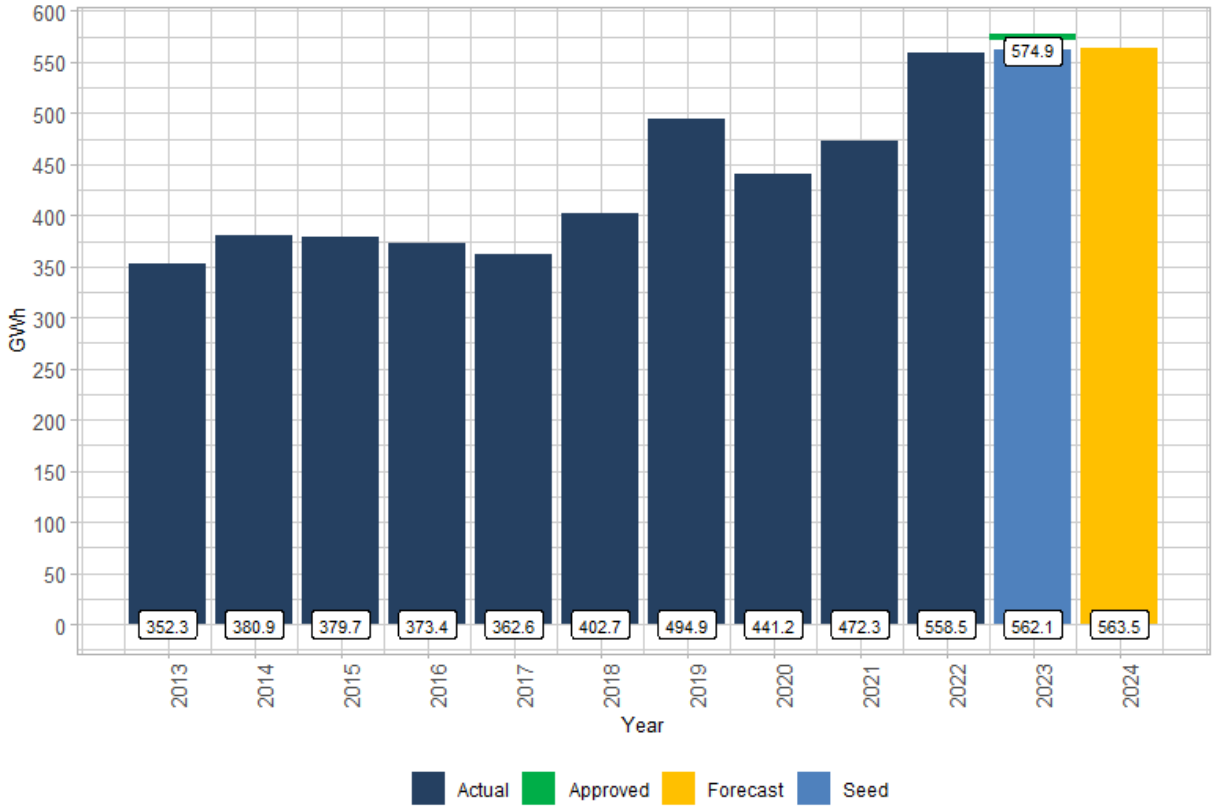
3.4.4 Industrial

Consistent with past practice, the industrial forecast is determined through a combination of customer load surveys and, when not available, escalation of the most recent annual loads by the corresponding provincial GDP growth rates for individual industries.

FBC sends all existing industrial customers a load survey that requests the customer's anticipated use for the next five years. A survey is used because individual industrial customers have the best understanding of what their future load will be. This year FBC received a response from 76 percent (32 of 42) of the surveys sent out. The responding customers represent approximately 91 percent of the total industrial load.

As shown in Figure 3-7 below, after-savings industrial load is forecast to increase by 1.4 GWh in 2024F when compared to 2023S and decrease by 11.4 GWh in 2024F compared to 2023 Approved.

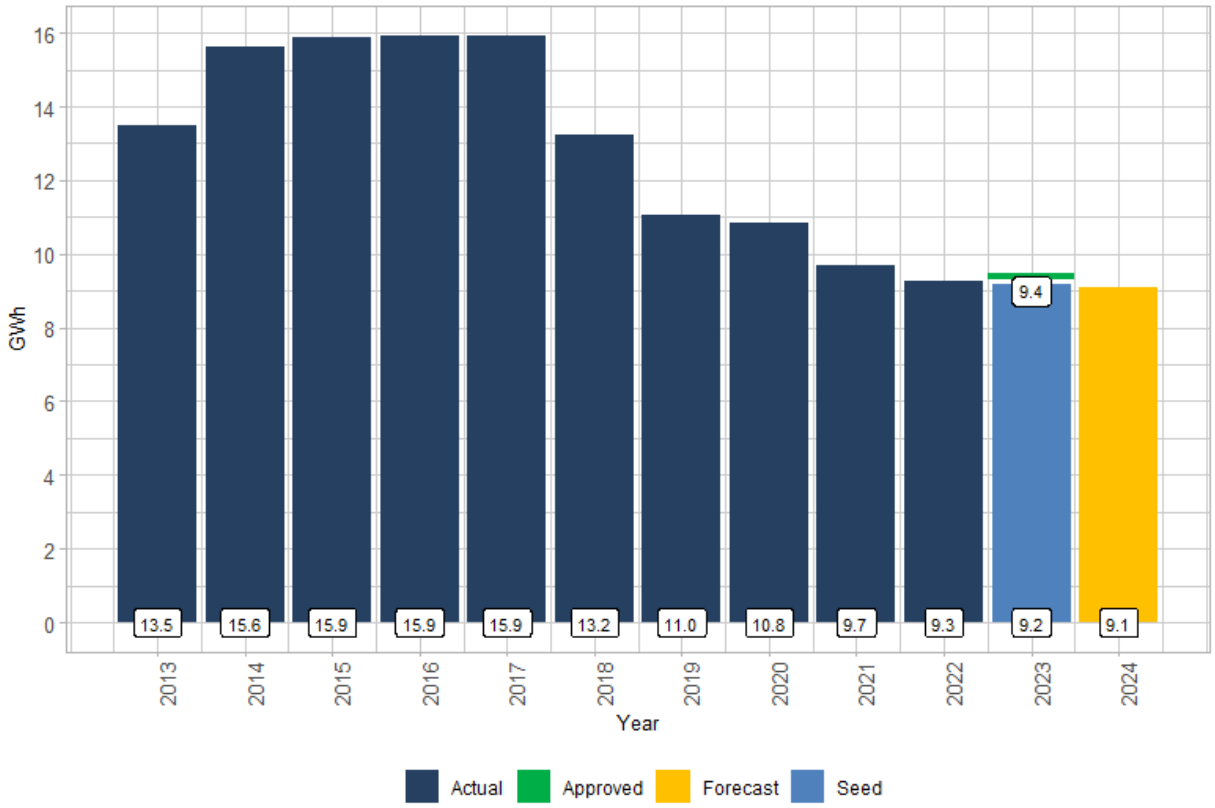
Figure 3-7: After-Savings Industrial Load (GWh)



3.4.5 Lighting

Due to the implementation of LED streetlights, the lighting load has been declining since 2017. FBC used the 2022 actuals as the forecast for this load and then reduced it by DSM savings. As shown in Figure 3-8 below, after-savings lighting load is forecast to decrease by 0.1 GWh in 2024F from 2023S and decrease by 0.3 GWh when compared to 2023 Approved.

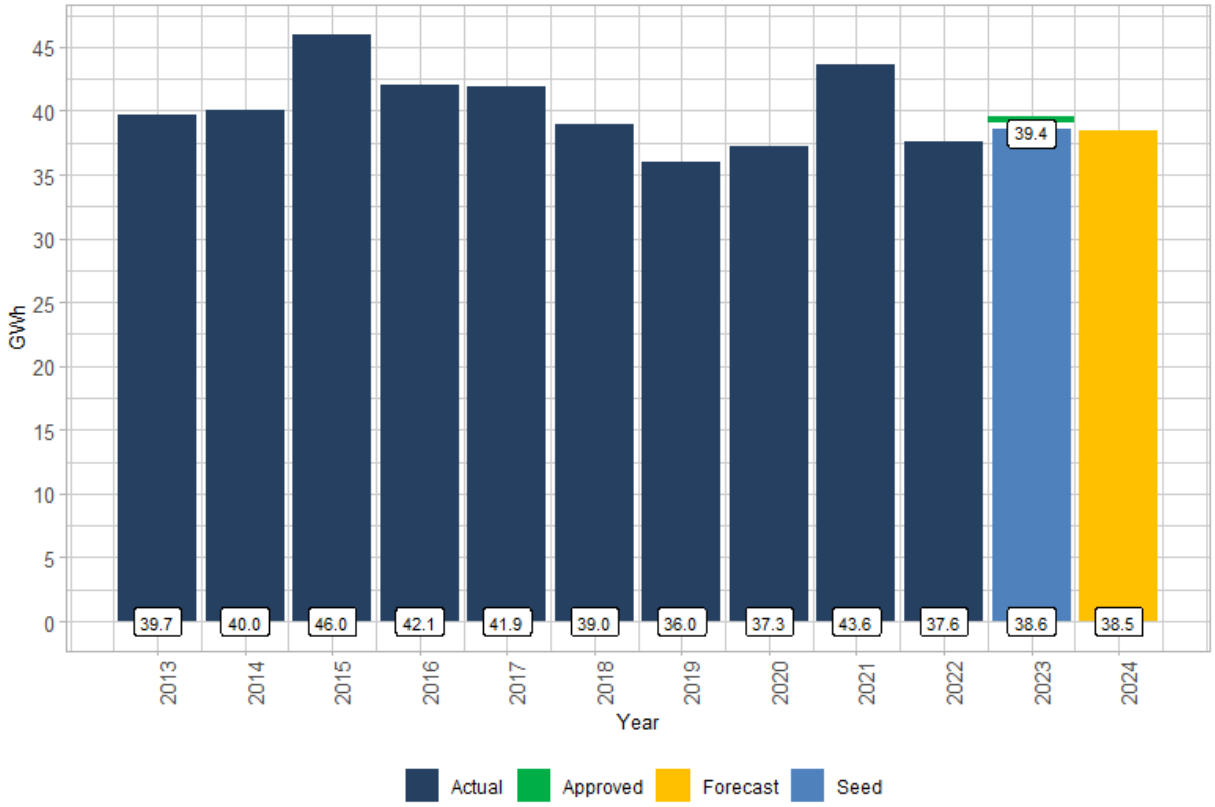
Figure 3-8: After-Savings Lighting Load (GWh)



3.4.6 Irrigation

Due to the variability in the load in the recent historical data, FBC used a five-year average as the forecast for the irrigation load. As shown in Figure 3-9 below, after-savings irrigation load is forecast to decrease by 0.1 GWh from 2023S to 2024F and decrease by 0.9 GWh in 2024F when compared to 2023 Approved.

Figure 3-9: After-Savings Irrigation Load (GWh)



3.4.7 Losses and Company Use

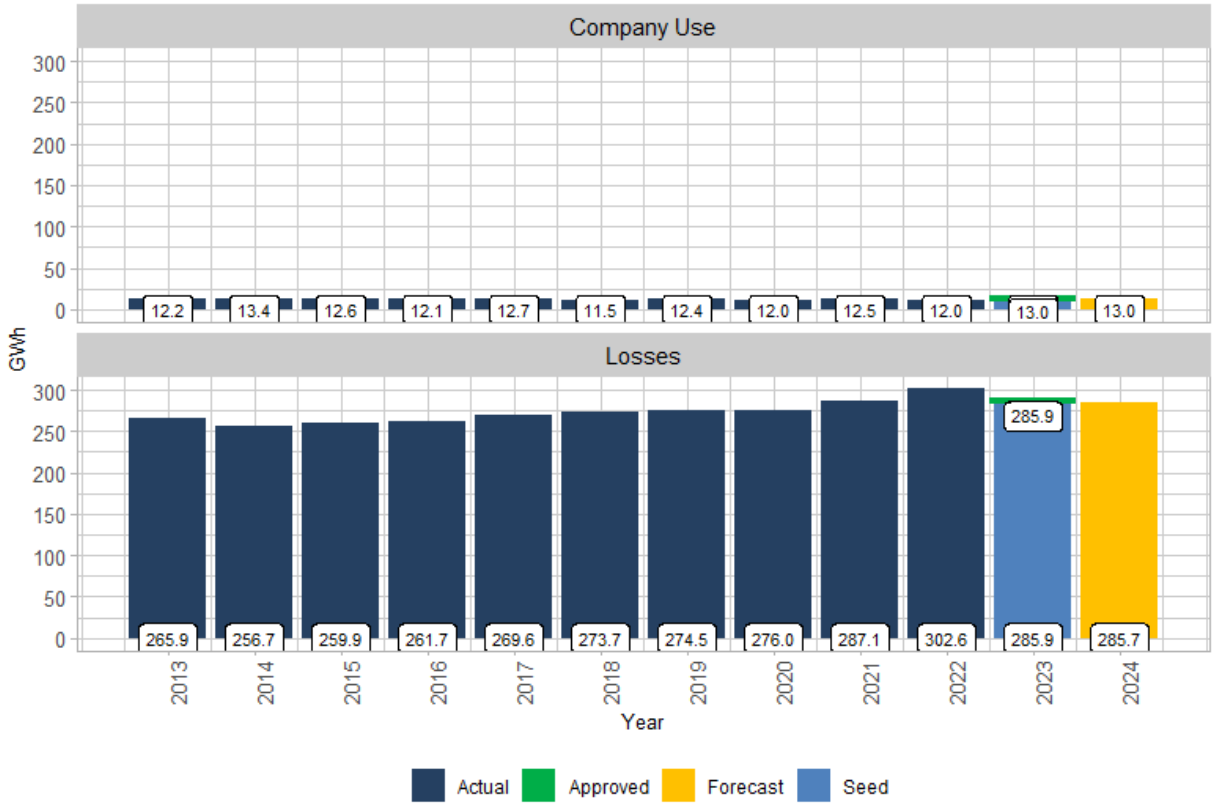
FBC conducted a Losses Study in 2019[10] and, consistent with that study, has assumed a loss rate of 7.6 percent of gross load (excluding company use). System losses consist of:

- Losses in the transmission and distribution system;
- Losses due to wheeling through the BC Hydro system; and
- Unaccounted-for load (meter inaccuracies and theft).

As shown in Figure 3-10 below, after-savings load losses are forecast to remain constant in 2024F because the gross load is forecast to be relatively stable when compared to 2023S. When compared to 2023 Approved, the 2024F after-savings load losses are forecast to decrease by 0.2 GWh due to decreased load. FBC has separated company use in the graph below, which is forecast at 13 GWh per year in 2024F, consistent with 2023S.

[10] MRP Application, Exhibit B-1-1, Appendix B3.

Figure 3-10: Normalized After-Savings Load Losses (GWh)



3.4.8 Peak Demand

The peak demand forecast is produced using the 10-year average of historical peaks, including peaks from the June 2021 "heat dome" event. The historical peak data is escalated by the gross load growth rate before it is averaged to account for the growth of demand on the FBC system.

Figures 3-11 and 3-12 below provide the historical winter peaks and summer peaks, respectively, from 2013 to 2022, as well as the estimates for 2023S and 2024F. To illustrate the non-weather-related growth in both winter and summer peaks over the last 10 years, the historical winter and summer peaks shown between 2013 and 2022 in Figures 3-11 and 3-12 below are weather-normalized and after-savings.

Furthermore, the peaks shown in both figures below are seasonal, i.e., the winter peak can fall in any month between November of the current year and February of the following year, and the summer peak can fall in any month between June and August.

Figure 3-11: After-Savings Winter Peaks (MW)

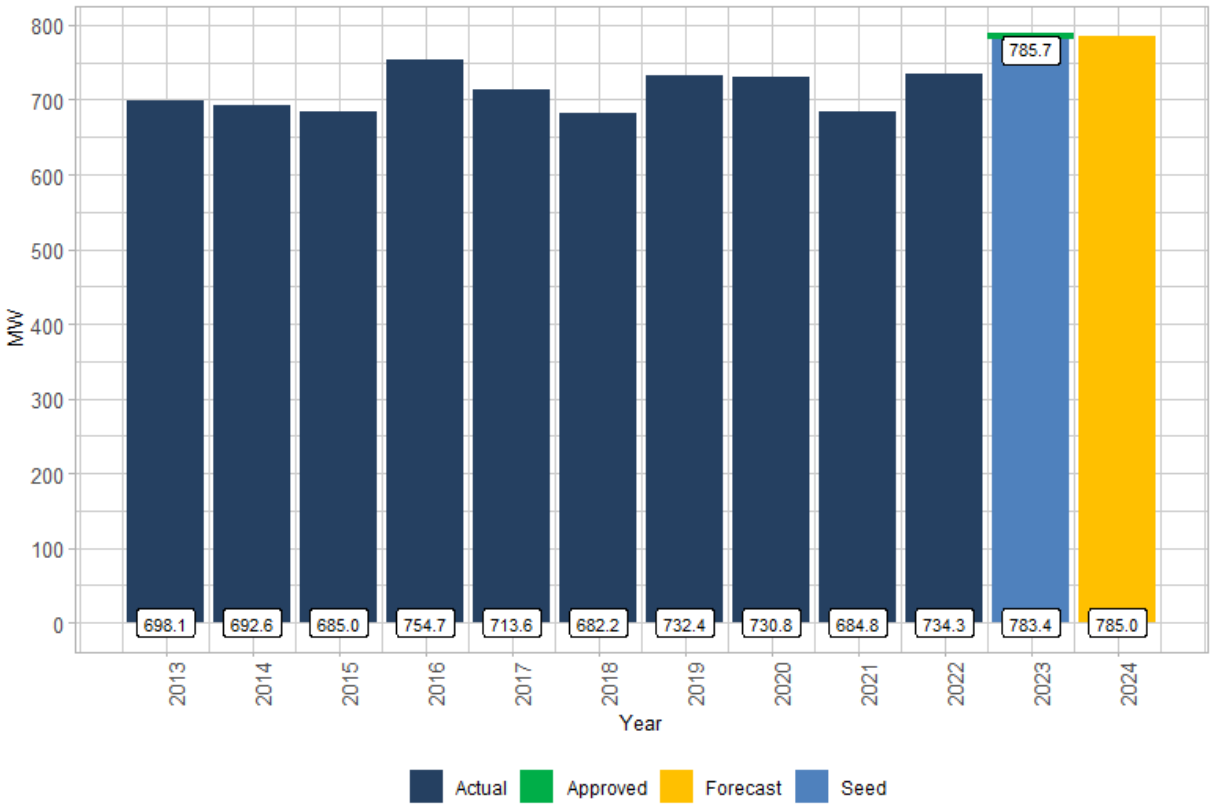
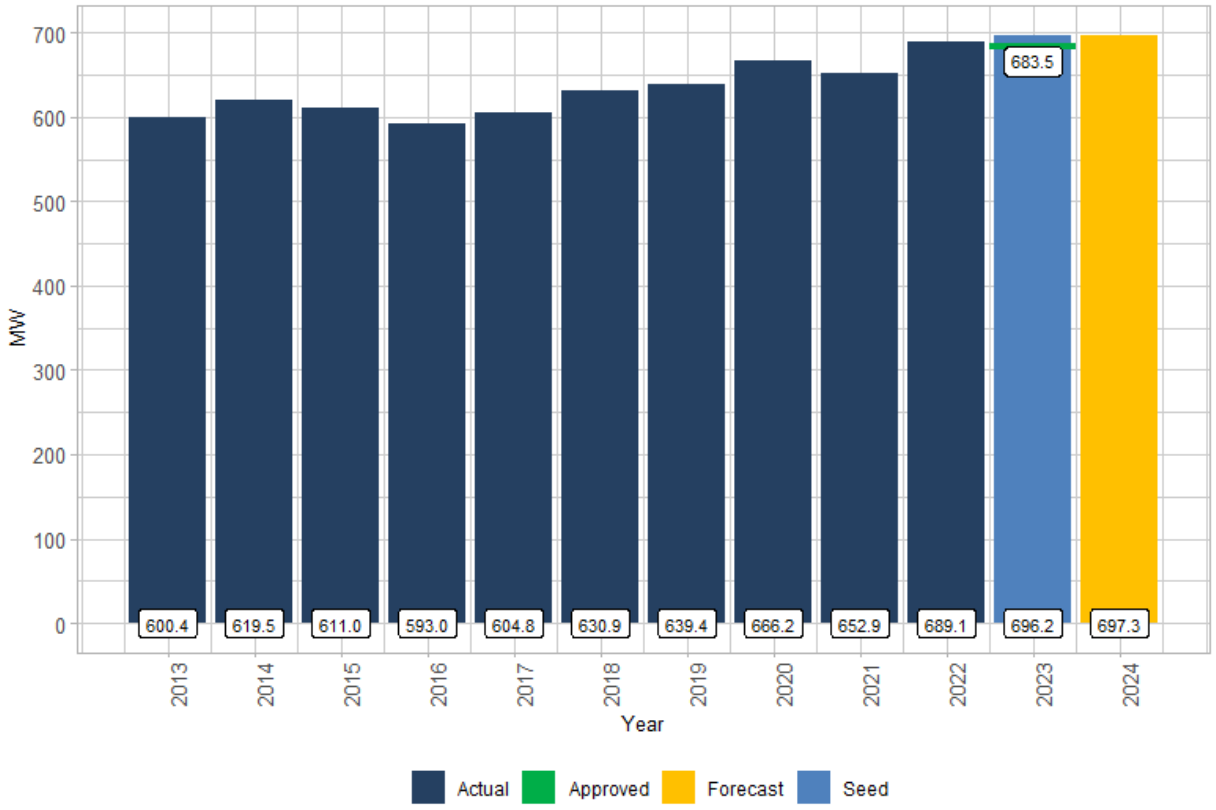


Figure 3-12: After-Savings Summer Peaks (MW)



3.5 CUSTOMER FORECAST

Table 3-3 shows the actual and forecast year-end customer counts by rate class. The residential and commercial customer counts are forecast using the methods described in Sections 3.4.1 and 3.4.2. Industrial customers are forecast based on information on expected new loads provided by key account managers. The lighting customer forecast is prepared using a five-year regression of year-end customer counts. Wholesale and irrigation customer counts are assumed to remain at 2022 levels.

Overall, for 2024F, FBC is forecasting customer growth of 1.5 percent compared to 2023S and growth of 0.7 percent compared to 2023 Approved.

Table 3-3: Customer Forecast[11]

Line No.	Description	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023S	2024F
1	Residential	111,862	113,431	114,166	115,772	117,748	120,291	122,465	124,966	126,678	129,131	131,323	133,291
2	Commercial	13,662	14,363	14,976	15,073	15,398	15,678	15,956	16,165	16,594	16,773	16,930	17,290
3	Wholesale	6	6	6	6	6	6	6	6	6	6	6	6
4	Industrial	47	49	50	50	50	52	51	43	42	42	42	42
5	Lighting	1,644	1,620	1,590	1,559	1,511	1,482	1,467	1,443	1,407	1,380	1,357	1,330
6	Irrigation	1,097	1,103	1,095	1,090	1,080	1,078	1,082	1,091	1,103	1,103	1,103	1,103
7	**Total**	128,318	130,572	131,883	133,550	135,793	138,587	141,027	143,714	145,830	148,435	150,761	153,063

3.6 RATE SCHEDULE 96 EV DCFC SERVICE FORECAST

On July 14, 2021, the BCUC issued Order G-215-21, which concluded that FBC's EV DCFC stations are prescribed undertakings under section 5 of the GGRR and approved flow-through treatment for the cost of service associated with the charging stations. By Order G-341-21 dated November 24, 2021, the BCUC approved the depreciation rate for the EV charging stations, and the inclusion of related revenues and expenses in FBC's regulated accounts. Following FBC's clarification on November 29, 2021 for the electricity input cost as directed in Decision and Order G-341-21, the BCUC approved the RS 96 rates on a permanent basis, by Order G-350-21 dated November 30, 2021, which include a time-based levelized rate[12] of $0.26 per minute and $0.54 per minute for FBC's 50 kW and 100 kW EV DCFC stations, respectively. FBC currently has a total of 42 EV DCFC stations in service across 22 sites and no additional stations are planned for 2023 or 2024.

As part of the Annual Review for 2022 Rates Decision and Order G-347-21[13], FBC was directed to:

- Provide an update on its EV DCFC charging stations' costs and revenues for the previous fiscal year along with a forecast of costs and revenues for the test period in future Annual Review filings.

Table 3-4 below provides the 2018 to 2022 Actual (i.e., previous fiscal years), 2023 Projected, and 2024 Forecast charging minutes and the resulting RS 96 revenues. Consistent with the approach presented in FBC's Revised and Updated EV DCFC Service Application dated September 30, 2020, the 2023 Projected and 2024 Forecast of charging minutes were determined based on the growth rates for ZEV sales targeted in the *BC ZEV Act*. These targets are 10 percent of ZEV sales by 2025, 30 percent by 2030, and 100 percent by 2040.[14]

[11] Direct customers only, i.e., excludes indirect wholesales customer counts.
[12] Including 15 percent transaction fees from FBC's EV DCFC vendor (i.e., AddEnergie, operator of the FLO EV charging network).
[13] Page 32.
[14] FBC's Revised and Updated EV DCFC Application, BCUC IR1 8.4 and CEC IR1 8.2. Additionally, as discussed in the RS 96 Assessment Report dated December 29, 2022, for forecasting purposes, FBC assumed the growth rates remain the same but are delayed by one year due to the COVID-19 pandemic.

It can be seen from Table 3-4 below that since the inception of FBC's charging stations (i.e., 50 kW in 2018 and 100 kW in 2021), the utilization rate has continued to grow, including in 2020 and 2021 when travel restrictions were in place due to the COVID-19 pandemic. Table 3-4 below also shows that there was a material increase in charging minutes from 2021 to 2022, which coincides with the ending of the aforementioned travel restrictions. FBC is expecting the upward trend will continue into 2024 with the growing number of electric vehicles available in the market. The upward trend that FBC is seeing with its EV DCFC service is consistent with the growth rates developed based on the ZEV sales targets used for the purpose of forecasting the charging minutes.

Table 3-4: FBC RS 96 EV DCFC Forecast

Line No.	Description	Actual 2018	Actual 2019	Actual 2020	Actual 2021	Actual 2022	Projected 2023	Forecast 2024
1	RS 96 Charging Minutes							
2	50 kW	15,309	94,386	110,504	229,342	410,783	584,194	782,820
3	100 kW	-	-	-	16,539	54,933	111,234	149,053
4	Total (Minutes)	15,309	94,386	110,504	245,881	465,716	695,428	931,874
5								
6	RS 96 Revenue, excl. 15% fee ($ millions)	$ 0.004	$ 0.024	$ 0.028	$ 0.058	$ 0.116	$ 0.180	$ 0.241

Table 3-5 below provides the cost of FBC's EV DCFC service for 2022 Actual, 2023 Projected and 2024 Forecast, including the RS 96 revenues shown in Table 3-4 above, and the prior years' surplus from 2018 to 2021.

FBC is currently forecasting a cumulative deficiency of $0.932 million from 2018 to 2024, including the 2024 forecast costs and revenue. FBC notes that the current RS 96 rates are set on a levelized basis which are designed to fully recover the forecast cost of service of the charging stations over the life of the stations, as such, deficiencies are expected in the early years of the service offering. Also contributing to the cumulative deficiency to date is the impact of the COVID-19 pandemic from 2019 to 2021 on the utilization of FBC's charging stations. As mentioned above, there has been a significant increase in the utilization of FBC's charging stations since 2022 and FBC expects the growth will continue. Furthermore, consistent with the approach in the Annual Review for 2023 Rates, FBC does not forecast revenue from the sale of carbon credits for future years due to the uncertainty in the timing of the credit validation as well as the market pricing. As such, FBC is not forecasting any carbon credit revenues in 2024. Please refer to Section 5.8 for further discussion of the carbon credits associated with FBC's EV DCFC stations which are recorded as Other Revenue. FBC expects the monetization of carbon credits will continue, which should help to reduce the overall deficiency in the future.

Table 3-5: EV DCFC Stations Costs and Revenues for 2022 Actual, 2023 Projected, and 2024 Forecast ($ millions)

Line No.	Description	Actual 2022	Projected 2023	Forecast 2024	Cumulative
1	Cost of Energy	0.136	0.177	0.197	
2	O&M	0.213	0.181	0.310	
3	Depreciation	0.456	0.551	0.593	
4	Amortization of CIAC	(0.190)	(0.236)	(0.249)	
5	Other Revenue - Carbon Credits	(0.744)	(0.544)	-	
6	Income Tax	(0.007)	0.048	0.132	
7	Earned Return	0.170	0.192	0.200	
8	Total Cost of Service	0.035	0.370	1.183	
9	RS 96 Revenue	(0.116)	(0.180)	(0.241)	
10	(Surplus) / Deficiency	(0.081)	0.190	0.942	1.050
11	Prior Year 2018-2021 (Surplus)/Deficiency				(0.119)
12	Cumulative (Surplus) / Deficiency				0.932

The RS 96 revenue (i.e., Line 9 of Table 3-5 above) is part of FBC's commercial sales revenue as presented in Section 3.7 below. Please also refer to Section 6.3.4 for a discussion of the forecast O&M expenses and Section 7.2.2 for a discussion of the forecast capital expenditures for the EV DCFC stations. Once the capital expenditures are included in rate base, they impact the depreciation, amortization of CIAC, income tax and earned return related to the EV DCFC stations that are shown in Table 3-5 above.

As directed by Order G-341-21, FBC filed a detailed assessment of the EV DCFC service on December 29, 2022 (RS 96 Assessment Report), which was accepted by the BCUC on June 19, 2023 by Letter L-33-23. As part of the RS 96 Assessment Report, FBC committed to providing an updated RS 96 Assessment Report by December 31, 2023, if an application for energy-based rates is not filed with the BCUC prior to this date.

3.7 REVENUE FORECAST

The forecast of revenues has been developed by applying approved 2023 rates to the forecast billing determinants for each customer class. Table 3-6 below summarizes the 2023 Approved, 2023 Projected and 2024 Forecast sales revenue. The commercial sales revenue shown in Table 3-6 below also includes the revenue from FBC's RS 96 EV DCFC stations discussed in Section 3.6.

Table 3-6: Forecast Sales Revenue at Approved Rates ($ millions)

Line No.	Description	Approved 2023	Projected 2023	Forecast 2024
1	Residential	$ 205.734	$ 208.939	$ 206.007
2	Commercial	110.490	111.741	110.808
3	Wholesale	54.100	55.279	55.574
4	Industrial	49.759	49.797	49.800
5	Lighting	2.295	2.298	2.221
6	Irrigation	3.695	3.666	3.967
7	Total	$ 426.073	$ 431.720	$ 428.377

When comparing the 2023 Projected to 2023 Approved, there is an increase in revenue of $5.647 million, primarily due to increases from the residential customer class, followed by increases from the commercial and wholesale customer classes.

For 2024, despite FBC forecasting a small reduction in net load of approximately 1 GWh (reduction in gross load of 2 GWh), FBC is forecasting an increase in revenue of $2.304 million when compared to 2023 Approved. The increase in revenue between 2024 Forecast and 2023 Approved is primarily due to the forecast increase in load from the wholesale customers as well as a forecast increase in residential and commercial customer counts (resulting in a small increase in the fixed monthly/bi-monthly customer charge). These increases are partially offset by reduced revenue from variable charges (i.e., $ per GWh) due to the forecast reduction in load from residential, industrial, and irrigation customers.

Variances between the revenue forecast in this section and the actual revenues realized are captured in the Flow-through deferral account.

3.8 SUMMARY

FBC is forecasting a decrease in consumption in 2024 compared to 2023 Approved. The 2024F gross load is forecast to be approximately 3,773 GWh, which is a 2 GWh decrease compared to the 2023 Approved gross load. Although the forecast load is decreasing in 2024, FBC is forecasting 2024 revenue to be $428.377 million, which is an increase of $2.304 million from 2023 Approved. This increase in revenue is primarily due to the forecast increase in load from the wholesale customers as well as an increase in residential and commercial customer counts (resulting in a small increase in the fixed monthly/bi-monthly customer charge), which is partially offset by reductions in load from residential, industrial, and irrigation customers.

4. POWER SUPPLY

4.1 INTRODUCTION AND OVERVIEW

This section includes a review of the 2023 Projected and 2024 Forecast power purchase expense (PPE), wheeling expense and water fees. Collectively, the PPE, wheeling expense and water fees are referred to as the power supply cost.

As shown in Table 4-1 below, the 2024 Forecast power supply cost of $193.532 million represents an increase of 6.3 percent or $11.427 million compared to the 2023 Approved cost of $182.105 million. The increase in 2024 Forecast power supply cost is driven primarily by the increase in PPE, although wheeling and water fee expenses have increased as well. The increase in the 2024 Forecast PPE is primarily the result of increased purchase rates for power. The 2024 Forecast wheeling expense has increased as a result of rates, partially offset by lower use. The 2024 Forecast water fee expense has increased compared to 2023 Approved as a result of rates and use.

Any variances between forecast and actual power supply costs are recorded in the Flow-through deferral account and returned to or recovered from customers in the subsequent year.

Table 4-1: Power Supply Cost ($ millions)

Line No.	Description	Approved 2023	Projected 2023	Forecast 2024
1	Power Purchase Expense	$ 163.575	$ 170.873	$ 173.694
2	Wheeling Expense	$ 6.987	$ 7.294	$ 7.324
3	Water Fees	$ 11.543	$ 12.433	$ 12.513
4	Total Power Supply Cost	$ 182.105	$ 190.600	$ 193.532
5				
6	Gross Load (GWh)	3,775	3,813	3,773

4.2 SUMMARY OF POWER SUPPLY RESOURCES

FBC uses a combination of Company-owned generation entitlements, firm contracted supply, and market purchases to meet its load requirements. The Company's firm resources consist of:

1. Canal Plant Agreement (CPA) Entitlements associated with the generation facilities owned by FBC. The costs associated with FBC-owned generation are not included in the power purchase estimates, except for the Balancing Pool adjustments, which account for year-to-year timing differences in the entitlement energy storage under the CPA;
2. The Brilliant Power Purchase Agreement (BPPA), a 125 MW contract (Order E-7-96), and an amendment to the BPPA which reflects the purchase of 20 MW of Brilliant Upgrade power (Letter L-57-00), and the 5 MW Brilliant Tailrace Capacity agreement (Order E-17-01);

3. A power purchase agreement (PPA) with BC Hydro (a 200 MW contract) under BC Hydro RS 3808 (Order G-60-14);

4. The Waneta Expansion Capacity Purchase Agreement (WAX CAPA), which is a 40-year purchase agreement with the Waneta Expansion Limited Partnership for capacity entitlements under the CPA (Orders E-29-10 and E-15-12);

5. A number of small Independent Power Producer (IPP) contracts; and

6. A number of market purchase arrangements.

4.3 PORTFOLIO OPTIMIZATION

The primary objectives of FBC's power supply portfolio planning are:

1. to ensure that the Company has sufficient firm resources to meet expected load requirements;

2. to ensure the availability of cost-effective reliable power for FBC's customers;

3. to prudently manage exposure to the cost and availability of market power supplies; and

4. to optimize the value of any surplus resources that are not needed to meet load requirements.

The Company currently has long-term, firm resources from which it can supply most of its forecast annual energy and capacity requirements. FBC's long-term, firm resources are capable of meeting FBC's forecast capacity requirements with the exception of June and a small number of hours during July. Consistent with the capacity self-sufficiency policy in FBC's 2021 Long Term Electric Resource Plan (LTERP), FBC will procure forward market blocks to cover these shortfalls on a planning basis. In addition, FBC is now forecasting small energy shortfalls emerging in November and December starting in 2024. Consistent with the accepted 2023/24 Annual Electric Contracting Plan (AECP), FBC will purchase winter energy blocks to address tightening winter energy supply and mitigate exposure to potential extreme spot market prices, should load exceed expected levels.

FBC's contracted resources, in particular the BC Hydro PPA, provide the Company some flexibility to participate in the market when conditions are favourable to mitigate the cost of holding these firm resources. However, over the past several years, the regional electricity market has been in a state of consistently higher prices compared to recent historical levels. This is due to several factors that include resource adequacy concerns, increased natural gas prices, and increased severe weather events. This change in the market price environment has resulted in little opportunity to displace Tranche 1, nominated PPA purchases on a forward basis.

Furthermore, although FBC's load requirements are forecast to grow over time, the amount of capacity provided under the WAX CAPA is currently greater than FBC's capacity requirements in

most months, and FBC sells the surplus capacity to mitigate power purchase expense. FBC has contracted to release a 50 MW block of capacity purchased under the WAX CAPA to BC Hydro under the Residual Capacity Agreement (RCA), which was approved by Order G-161-14. The remaining surplus WAX CAPA will be sold to Powerex Corp. (Powerex) on a day-ahead basis, if and when it is not required to meet FBC load requirements. These sales are made under the Capacity and Energy Purchase and Sale Agreement (CEPSA) with Powerex dated February 17, 2015, and accepted by Order E-10-15.

4.4 FBC 2023/24 ANNUAL ELECTRIC CONTRACTING PLAN

On April 28, 2023, FBC filed its 2023/24 AECP with the BCUC. The purpose of the AECP is to outline FBC's plan to meet its peak demand requirements and annual energy requirements for the operating year commencing October 1, 2023 and ending September 30, 2024, and to facilitate FBC's annual energy nomination under the PPA. FBC is required to take or pay for 75 percent of the PPA Nomination, regardless of whether it schedules the energy. The difference between the PPA Nomination and the 75 percent minimum take provides flexibility to manage annual loads that are below forecast or to displace PPA purchases with lower cost market purchases. Therefore, real-time opportunities to displace PPA purchases are restricted to a maximum of 25 percent of the PPA nominated energy, but could be more or less, depending on system conditions.[15] The AECP also outlines FBC's load and resource balance over the following four years, and FBC's plan for optimizing its portfolio over that period. FBC's forecasts of PPE for the remainder of 2023 and for 2024 are based on the plan detailed in the 2023/24 AECP, which was accepted by the BCUC on June 1, 2023, by Letter L-24-23.[16]

The AECP identified FBC's intention to make its annual energy nomination under the PPA for the 2023/24 contract year equal to 929 GWh, less any firm market contracts that FBC could enter, as described in Section 5 of the 2023/24 AECP. Prior to the June 30, 2023 nomination deadline, FBC updated its forecast load and resource balance for the 2023/24 contract year and submitted a nomination of 929 GWh.

4.5 2023 PROJECTED POWER PURCHASE EXPENSE

As shown in Table 4-2 below, FBC's 2023 Projected gross load (after taking into account demand side management and other customer savings) is expected to be 38 GWh above the 2023 Approved value, and PPE is projected to be above the 2023 Approved value by $7.298 million. The rise in 2023 Projected PPE is primarily due to increased Market and Contracted Purchase expense as a result of increased volumes and rates.

[15] For example, if loads were 50 GWh lower in a year than forecast, that must be adjusted for as part of the 25 percent PPA flexibility such that the amount of PPA energy that can be displaced by market purchases is also reduced by 50 GWh.

[16] The AECP was filed confidentially. The non-confidential Executive Summary is attached to Letter L-24-23.

A majority of the increase in volume and cost was due to FBC purchasing wholesale market power from the spot market, at rates economic to the PPA during the first six months of the year to reduce required purchases above the BC Hydro PPA Nomination. In contrast, there was a relatively small amount of wholesale market contracts included in the 2023 Approved figures, as forward market contract prices resulted in little opportunity to displace PPA on a forward basis. In addition, FBC purchased forward market blocks to cover projected capacity shortfalls in June 2023 and reduce exposure to Tranche 2 energy under the PPA with BC Hydro. Also included in the Projected 2023 expense are planned wholesale market purchases in November and December 2023, consistent with the strategy presented in the 2023/24 AECP.

While forecast market savings included in the 2023 Approved[17] did materialize during the first six months of the year, FBC has not included any forecast savings for the remainder of 2023 within the Projected PPE. This is due to the current forward market price premium compared to rates for PPA purchases for the remainder of 2023.

Partially offsetting the increase in PPE is a reduction to the Waneta Expansion Expense due to increased forecast surplus sales revenue under the RCA and CEPSA.

Table 4-2: 2023 Power Purchase Expense ($ millions)

Line No.	Description	Approved 2023	Projected 2023	Difference
1	Brilliant	$ 44.050	$ 44.048	$ (0.002)
2	BC Hydro PPA	71.302	70.702	(0.600)
3	Waneta Expansion	41.834	38.351	(3.483)
4	Market and Contracted Purchases	6.326	18.624	12.297
6	Independent Power Producers	0.062	0.195	0.133
7	Self-Generators	-	0.044	0.044
8	CPA Balancing Pool	(0.000)	(1.570)	(1.570)
9	Transmission Service Loss Recoveries	-	-	-
10	Special and Accounting Adjustments	-	0.479	0.479
11	Total	$ 163.575	$ 170.873	$ 7.298
12				
13	Gross Load (GWh)	3,775	3,813	38

4.6 2024 FORECAST POWER PURCHASE EXPENSE

As shown in Table 4-3 below, the 2024 Forecast PPE is $2.821 million above the 2023 Projected. The forecast increase from $170.873 million in 2023 to $173.694 million in 2024 is primarily a result of an increase in BC Hydro PPA expenses and escalation of Waneta Expansion rates. This is partially offset by a decrease in Market and Contracted Purchases due to volume. FBC is increasingly reliant on energy supplied by BC Hydro as it is generally more cost effective than the market during most times of the year. However, FBC also requires wholesale market purchases

[17] 2023 Approved included $7.000 million in potential real-time opportunities, including $3.500 million forecast for the first six months. FBC was able to exceed the $3.500 million during the first six months of 2023 but does not expect any further savings for the remainder of 2023.

to address supply gaps and reduce exposure to potentially extreme market prices, beyond what can be supplied by the PPA. Escalations to the Brilliant contract rates are also contributing to increased costs.

Table 4-3 below shows a comparison of the 2023 Projected and 2024 Forecast PPE. Reasons for significant variances from the 2023 Projected PPE are discussed below.

Table 4-3: 2024 Forecast Power Purchase Expense ($ millions)

Line No.	Description	Projected 2023	Forecast 2024	Difference
1	Brilliant	$ 44.048	$ 44.433	$ 0.385
2	BC Hydro PPA	$ 70.702	71.680	0.978
3	Waneta Expansion	$ 38.351	40.365	2.014
4	Market and Contracted Purchases	$ 18.624	16.972	(1.652)
5	Independent Power Producers	$ 0.195	0.245	0.050
6	Self-Generators	$ 0.044	-	(0.044)
7	CPA Balancing Pool	$ (1.570)	0.000	1.570
8	Transmission Service Loss Recoveries	-	-	-
9	Special and Accounting Adjustments	$ 0.479	-	(0.479)
10	Total	$ 170.873	$ 173.694	$ 2.821
11				
12	Gross Load (GWh)	3,813	3,773	(40)

4.6.1 Brilliant

Brilliant expense is forecast to increase in 2024 by $0.385 million compared to 2023 Projected due to increased rates, which are based on a forecast of the operating and maintenance cost of the plant, as well as a true-up to the prior year's actual costs compared to forecast.

4.6.2 BC Hydro PPA

BC Hydro PPA expense is forecast to increase in 2024 by $0.978 million compared to the 2023 Projected expense. The drivers of the variance are a higher purchased volume (62 GWh), which increases the expense by $4.046 million, offset by a lower average purchase rate for BC Hydro PPA,[18] which accounts for a decrease of $0.068 million, for a total increase of $3.978 million. FBC has decreased its 2024 Forecast of PPA expense by $3.000 million in savings to account for potential real-time opportunities to displace PPA purchases with lower cost market purchases. The 2023 Projected BC Hydro expense does not include any adjustment for potential real-time opportunities for the remainder of 2023. This results in a variance between 2023 Projected and 2024 Forecast of $0.978 million[19], as shown in Table 4-3. Actual market savings for the remainder of 2023 and 2024 may be higher or lower and will depend on system and market conditions at

[18] A higher PPA nomination for the 2023/24 contract year results in less penalty charges from energy taken over and above the PPA nomination and a lower average BC Hydro PPA purchase rate.

[19] $0.978 million is calculated as follows: Total increase of $3.978 million less the $3.000 million 2024 Forecast real-time opportunities.

the time. Any variance, including these savings, is recorded in the Flow-through deferral account and returned to or recovered from customers in a subsequent year.

4.6.3 Waneta Expansion

The $2.014 million increase in Waneta Expansion expense is due to the 2.1 percent annual fixed escalation of WAX CAPA rates, and a $0.549 million decrease in forecast surplus sales revenue under the RCA and CEPSA. Revenue under the CEPSA is linked to the amount of capacity FBC releases to Powerex and the day-ahead market prices at the Mid-Columbia River (Mid-C) trading hub. The Mid-C is the largest electricity trading hub in the Pacific Northwest and is located on the US portion of the Columbia River. CEPSA revenue is forecast using the average monthly sales revenue from the past three years. The forecast of surplus capacity sales revenue in 2024, which is included in Line 3 of Table 4-3, is approximately $13.636 million.

4.6.4 Market and Contracted Purchases

The $1.652 million decrease in Market and Contracted Purchases forecast for 2024 is a result of reduced volume when compared to 2023 Projected. Market and Contracted Purchases for 2023 Projected include fixed price contracted purchases, year to date real-time market purchases and forecast purchases in November and December 2023 at forward market rates. Market purchases included in the 2024 Forecast include fixed price contracted purchases, as well as forecast wholesale market purchases at current forward market rates to cover energy requirements in January, February, November and December, and capacity shortfalls in June and July 2024. Forecast real-time market purchases for Rate Schedule 37[20] load are also included. As discussed above in the BC Hydro PPA variance explanation, there may be opportunities for additional real-time market purchases using the flexibility of the PPA purchases.

4.6.5 CPA Balancing Pool

The CPA Balancing Pool represents timing differences in entitlement energy storage under the CPA and is used to manage fluctuations in load and resource availability, or to take advantage of market opportunities. In the 2023 Projected PPE, FBC has stored a net total of 31 GWh of entitlement energy, valued at $1.570 million. For the 2024 Forecast, and consistent with past practice, FBC does not forecast any net use or storage of entitlement energy.

4.7 TRANSMISSION SERVICE LOSS RECOVERIES

Transmission service customers taking service under FBC's Rate Schedules 100 and 101 currently physically deliver energy to FBC to compensate for the losses that are incurred on FBC's system as a result of wheeled energy. FBC includes transmission wheeling losses in its load

[20] RS 37 is large commercial stand-by service, which is an on-demand back-up and maintenance service provided to self-generating customers. This service is provided to the customer at an hourly market-based rate, reflective of FBC's cost of supply. FBC procures this supply on a real-time basis because there is little certainty as to when customers will use this service. Forecast RS 37 load for 2024 is 15 GWh or 0.4 percent of total gross load.

forecast (included in Tables 4-2 and 4-3, Line 8), and also includes loss recovery as a firm resource. Because the recoveries are delivered physically, there is no associated cost or revenue. Table 4-4 shows the 2023 and 2024 loss recoveries.

Table 4-4: Transmission Service Loss Recoveries (GWh)

Line No.	Description	Approved 2023	Projected 2023	Forecast 2024
1	Loss Recoveries	12	12	12

4.8 WHEELING EXPENSE

Wheeling expense includes wheeling service provided by BC Hydro under the Amended and Restated Wheeling Agreement (ARWA) and Open Access Transmission Tariff (OATT) as needed to supply the Company's loads in the Okanagan, Creston and Princeton. Also included are charges paid to Teck Metals Ltd. (Teck) for the use of its 71 Line. Rates under the ARWA are specified in BC Hydro's RS 3817.

Wheeling expense is forecast using the same method as in the Annual Review for 2023 Rates.[21] Table 4-5 below shows FBC's Wheeling Expense for 2023 and 2024.

Table 4-5: Wheeling Expense ($ millions)

Line No.	Description		Approved 2023	Projected 2023	Forecast 2024
1	Wheeling Nomination (MW Months)				
2	Okanagan Point of Interconnection		2,670	2,670	2,595
3	Creston		420	420	450
4					
5	Wheeling Expense				
6	Okanagan Point of Interconnection	$	5.555	5.786	5.813
7	Creston		0.570	0.593	0.658
8	Other		0.863	0.914	0.854
9	Total Wheeling Expense	$	6.987	7.294	7.324

Total 2023 Projected wheeling expense is $0.307 million greater than 2023 Approved. The 2023 Projected ARWA costs are $6.380 million (Lines 6 and 7 in the table above), a $0.255 million increase when compared to 2023 Approved, which is a result of higher than expected BC-CPI and therefore ARWA rates. 2023 Projected Teck and OATT wheeling costs are $0.914 million (Line 8 above), which is $0.051 greater than 2023 Approved. This is mainly due to increased use of OATT wheeling.

[21] ARWA expense is forecast using known volumes and prior year's rates escalated by estimated BC-CPI. Teck wheeling is forecast based on the previous year's costs and escalated by 2 percent annually per contract. OATT wheeling costs are estimated using an average of prior years' expenses.

2024 Forecast wheeling expense is $0.030 million higher than 2023 Projected. This is a result of increased rates. FBC decreased the ARWA Okanagan wheeling nomination to 2,595 MW months in 2024 from 2,670 MW months in 2023. ARWA rates are forecast to increase on October 1 of both 2023 and 2024 based on forecast BC-CPI, as is the Teck wheeling rate as a result of a letter agreement made between Teck and FBC.

4.9 WATER FEES

Water fees are based on FBC's entitlement usage in the previous year and the rate increases are indexed to BC-CPI.

As shown in Table 4-6 below, the 2024 Forecast water fees are increasing by $0.080 million from the 2023 Projected due to increased rates.

Table 4-6: Water Fees ($ millions)

Line No.	Description	Approved 2023	Projected 2023	Forecast 2024
1	Plant Entitlement in Previous Year (GWh)	1,571	1,585	1,561
2				
3	Water Fees	$ 11.543	$ 12.433	$ 12.513

4.10 SUMMARY

FBC's forecast of PPE is based on FBC's firm resources in place at the time of filing, as well as forecast market purchases, and is consistent with the 2023/24 AECP. Any variances in the power supply cost, including any decreases in PPE due to further portfolio optimization, are recorded in the Flow-through deferral account and returned to or recovered from customers in a subsequent year.

5. OTHER REVENUE

5.1 INTRODUCTION AND OVERVIEW

This section discusses FBC's forecasts of Other Revenue. In the MRP Decision (page 74), FBC was approved for variances between forecast and actual Other Revenue to be subject to earnings sharing.[22]

FBC is forecasting Other Revenue for 2024 to be $0.149 million lower than 2023 Approved, primarily due to lower Contract Revenue and Transmission Access Revenue.

2023 Projected Other Revenue is $0.622 million higher than 2023 Approved. The main drivers of this increase are the sales of carbon credits related to Electric Vehicle (EV) Direct Current Fast Charging (DCFC) stations, as well as higher Contract Revenue.

Table 5-1: Other Revenue ($ millions)

Line No.	Description	Approved 2023	Projected 2023	Forecast 2024
1	Apparatus and Facilities Rental	$ 6.108	$ 6.108	$ 6.199
2	Contract Revenue	2.367	2.591	2.260
3	Transmission Access Revenue	1.834	1.716	1.723
4	Interest Income	0.030	0.035	0.037
5	Late Payment Charges	0.994	0.961	0.962
6	Connection Charges	0.553	0.553	0.561
7	EV Stations Carbon Credits	-	0.544	-
8	Other Recoveries	0.355	0.355	0.351
9	Total Other Revenue	$ 12.241	$ 12.863	$ 12.092

In the following sections, FBC summarizes its projections and forecasts for each of the line items included in the table above.

5.2 APPARATUS AND FACILITIES RENTAL

Apparatus and Facilities Rental is comprised primarily of pole contact revenue from other utilities and businesses that attach their facilities to FBC infrastructure in order to deliver services to their customers, such as telephone and cable television providers. Rent is charged at a unit rate per pole contact multiplied by the number of poles that are contacted. There are no variances projected in 2023 compared to 2023 Approved, as final amounts have yet to be calculated since the majority of invoices are issued during the third quarter of the year. The 2024 Forecast is higher than 2023 Approved due to expected escalations in unit rental rates for continuing contracts.

[22] Variances in Other Revenue associated with Electric Vehicle (EV) stations carbon credits are treated as flow-through, as EV Direct Current Fast Charging (DCFC) stations are prescribed undertakings under section 5 of the GGRR and the cost of service associated with EV DCFC stations is subject to flow-through treatment.

5.3 CONTRACT REVENUE

FBC performs work under contract to third parties at the Waneta and Brilliant hydroelectric generating facilities. This third-party work, and the associated management fees earned, fluctuates from year to year based on customer requirements, which include routine and non-routine work planned at the start of the customer's fiscal year.

The Company also operates and maintains a number of other facilities for third-party entities through its non-regulated affiliate FortisBC Pacific Holdings Inc. (FPHI). Transactions between FBC and FPHI are conducted in accordance with FBC's Code of Conduct and Transfer Pricing Policy[23] and earn a transfer price profit revenue. Revenues may fluctuate from year to year depending on customer requirements.

The 2023 Projected revenue is higher than 2023 Approved due to higher expected transfer price profit revenue on facilities operated and maintained by FPHI, based on amounts earned so far in 2023. The 2024 Forecast is slightly lower than 2023 Approved due to less customer requirements expected as a result of a higher level of work performed in the last few years for one customer, which is expected to decrease the need for non-routine work.

5.4 TRANSMISSION ACCESS REVENUE

Transmission Access Revenue represents charges to customers for transmitting power over the FBC system. The 2023 Projected revenue is lower than 2023 Approved due to a lower nomination than originally forecast for one customer. The 2024 Forecast is also lower than 2023 Approved due to lower nominations expected.

5.5 INTEREST INCOME

Interest Income is primarily comprised of DSM loan interest income, as well as other banking interest income. The Company is not forecasting significant changes in the amount of DSM loans outstanding or cash balances on hand attracting interest; as a result, although higher interest rates are available, no significant changes in interest income are expected in 2023 Projected or the 2024 Forecast.

5.6 LATE PAYMENT CHARGES

As explained in the Annual Review for 2023 Rates, Late Payment Charges were historically forecast based on the average of the most recent three years of actual Late Payment Charges earned. However, due to a number of factors in the most recent years, including the COVID-19 pandemic and FBC's implementation of customer relief measures, the actual amounts collected have fluctuated significantly from year to year. As these fluctuations would still be present in the most recent three years of actual results (i.e., 2020, 2021 and 2022), FBC has utilized the same

[23] As approved by Order G-5-10A.

approach used to calculate the 2023 Approved Late Payment Charges in the 2023 Annual Review. Accordingly, the 2024 Forecast for Late Payment Charges is calculated based on the average of 2022 Actual Late Payment Charges of $0.962 million and 2023 Projected of $0.961 million. This results in a forecast decrease in Late Payment Charges of $0.032 million compared to 2023 Approved and is generally consistent with the 2023 Projected amount.

5.7 CONNECTION CHARGES

Connection Charges are calculated based on the fees specified in FBC's rate schedules applicable to new customer connections or current customer reconnections. The 2023 Projected is expected to be consistent with 2023 Approved based on amounts charged so far in 2023. The 2024 Forecast is expected to be slightly higher than 2023 Approved based on customer growth and forecast customer reconnections.

5.8 CLEAN GROWTH INITIATIVE – EV DCFC STATIONS CARBON CREDITS

As discussed in Section 3.6, FBC's EV DCFC stations are prescribed undertakings under Section 5 of the GGRR[24] and the cost of service associated with EV DCFC stations is subject to flow-through treatment. Please refer to Table 3-5 in Section 3.6 for a summary of EV DCFC station costs and revenues from 2022 Actual to 2024 Forecast.

The sale of the carbon credits related to EV DCFC stations[25] earned under the Renewable Low Carbon Fuel Requirements Regulation (RLCFRR) is recorded as Other Revenue in FBC's regulated accounts, which is embedded in the rate design of the EV DCFC stations.

FBC anticipates that 1,210 credits from the 2021 compliance period, with an approximate value of $0.544 million,[26] will be monetized prior to the end of 2023 and has therefore included this amount in 2023 Projected Other Revenue. Since FBC did not forecast any monetization of carbon credits in the 2023 Approved amount as part of the Annual Review for 2023 Rates, the variance between the 2023 Projected amount of $0.544 million and the 2023 Approved amount of zero will be captured in the Flow-through deferral account and returned to customers in 2024 rates. Consistent with the approach described in the Annual Review for 2023 Rates, FBC does not forecast revenue from the sale of credits for future years due to the uncertainty in the timing of the credit validation as well as the market pricing. As such, FBC is not forecasting any carbon credit revenues in 2024. As noted above, the cost of service associated with EV DCFC stations is subject to flow-through treatment. Therefore, any variances between actual and forecast sales

[24] Order G-215-21 dated July 14, 2021.

[25] Includes both public charging stations owned by FBC as well as public stations owned by other entities (metered commercial accounts) as discussed in Exhibit B-6 of FBC's Annual Review for 2022 Rates, BCSEA IR1 4.3. Beginning in 2022, FBC is only permitted to claim credits for charging stations owned by FBC. FBC does not currently claim credits for non-public EV charging services for either commercial or residential customers.

[26] 1,210 credits x $449.20 average Q1-2023 sales price (source: https://www2.gov.bc.ca/gov/content/industry/electricity-alternative-energy/transportation-energies/renewable-low-carbon-fuels/credits-market)

of carbon credits will be captured in the Flow-through deferral account and returned to customers in the subsequent year.

5.9 OTHER RECOVERIES

Other Recoveries are primarily comprised of fees earned on the recovery of costs for miscellaneous services, such as street light maintenance charged to municipalities and AMI radio-off meter read fees. There are no variances expected in 2023 Projected compared to 2023 Approved based on amounts recognized to date. The 2024 Forecast is expected to be slightly lower than 2023 Approved due to an expected reduction in AMI radio-off meter read fees resulting from a lower volume of customers choosing the radio-off option.

5.10 SUMMARY

FBC has forecast the Other Revenue components for 2024 reflecting all applicable contracts and fixed revenues, and based on the Company's best knowledge of the factors that drive the variable components. Variances in Other Revenue, with the exception of EV DCFC stations carbon credits, are shared with customers through the earnings sharing mechanism.

6. O&M EXPENSE

6.1 INTRODUCTION AND OVERVIEW

Under the MRP, FBC's O&M expense is primarily determined by formula, with the addition of a certain items that are forecast outside the formula on an annual basis.

In 2024, the formula O&M is $72.823 million, representing a 3.6 percent increase from the 2023 formula O&M, primarily due to the formula drivers. O&M expenses forecast outside the formula for 2024 are $1.499 million, representing a 36.2 percent decrease from the amount approved for 2023. Overall, the 2024 Forecast gross O&M expense is $74.322 million, which is an increase of approximately 2.3 percent from the 2023 Approved level.

The components of 2024 O&M expense are shown in Table 6-1 below.

Table 6-1: 2024 O&M Expense ($ millions)

Line No.	Description	Approved 2023	Projected 2023	Forecast 2024	Reference
1	Formula O&M	$ 70.318	$ 70.318	$ 72.823	Section 11, Schedule 20, Line 8
2	Forecast O&M	2.349	2.361	1.499	Section 11, Schedule 20, Line 20
3	Total Gross O&M	72.667	72.679	74.322	Line 1 + Line 2
4	Capitalized Overhead	(10.900)	(10.900)	(11.148)	Section 11, Schedule 20, Line 23
5	Net O&M	$ 61.767	$ 61.779	$ 63.174	Line 3 + Line 4

In the sections below, FBC provides further details on its formula and forecast O&M expenses for 2024. Additionally, in compliance with the BCUC's directive in the MRP Decision,[27] FBC provides information related to its System Operations, Integrity and Security expenditures in Subsection 6.2.1.

6.2 FORMULA O&M EXPENSE

The formula-driven portion of O&M starts from the prior year's Approved Base O&M per Customer (UCOM), escalated by the prior year's inflation less a productivity improvement factor of 0.5 percent, and then multiplied by 75 percent of the forecast growth in average customers, resulting in the current year inflation-indexed O&M before true-up. A true-up of formula O&M based on actual average customers from two years prior is then added to the current year inflation-indexed O&M.

As calculated in Section 2, the 2024 inflation based on prior year's BC-CPI and BC-AWE, less the productivity improvement factor, is 3.580 percent.

For 2024, the annual operating and maintenance expense under the formula is calculated as:

[27] MRP Decision, p. 118.

2023 Approved formula UCOM x [1 + (I Factor – X Factor)] x [Prior Year Average Customers + (0.75 x growth in average customers)] + 2022 Formula O&M True-up

Table 6-2 below shows the calculation of the 2024 Formula O&M, including the calculation of the 2022 Formula O&M true-up. FBC notes the true-up of formula O&M is a two-year lag based on actual average customer counts from 2022.

Table 6-2: Calculation of 2024 Formula O&M ($ millions)

Line No.	Description		Forecast 2024	Reference
1	Prior Year Base Unit Cost O&M ($/ customer)	$	472	G-382-22 FBC 2023 Annual Review
2	I-Factor		3.580%	Section 2, Table 2-3, Line 11
3	Current Year Unit Cost O&M ($/customer)	$	489	
4	Average Customer Forecast		148,984	Section 2, Table 2-3, Line 13
5	2024 Inflation-Indexed O&M before 2022 True-up	$	72.853	Line 3 x Line 4 / 1,000,000
6	2022 True-up O&M		(0.030)	Line 16
7	Inflation-Indexed O&M	$	72.823	Line 5 + Line 6
8				
9	2022 O&M True-up			
10	2022 Actual 12 month Average Customers		147,112	FBC 2022 Annual Report
11	2022 Forecast 12 month Average Customers		147,199	G-374-21 FBC 2022 Annual Review
12	Difference		(87)	Line 10 + Line 11
13	Growth Factor		75%	G-166-20 FBC MRP Decision
14	Change in Customers - True-up		(65)	Line 12 x Line 13
15	2022 Unit Costs	$	455	G-374-21 FBC 2022 Annual Review
16	O&M True-up for 2024	$	(0.030)	Line 14 x Line 15 / 1,000,000

6.2.1 New/Incremental System Operations, Integrity and Security Funding

In the MRP Decision (page 118), the BCUC directed FBC to provide in each Annual Review a breakdown and explanation of both annual and cumulative variances between forecast/actual and formula O&M related to the approved new/incremental System Operations, Integrity and Security funding, and quantify the variances attributable to the following areas: tree management; generation dam safety; network operations apprentice program; cyber security; data analytics; and any other significant factors or miscellaneous items.

The table below shows the requested information, including the new/incremental funding in each category for 2022 Formula O&M, 2022 Actual O&M, and the resulting variances, as well as the Cumulative Forecast/Actual variance for the first three years of the MRP.

Table 6-3: System Operations, Integrity and Security New/Incremental Spending ($ millions)

Line No.	Description	2022 Formula O&M	Actual 2022 O&M	2022 Forecast/Actual Variance	Cumulative Forecast/Actual Variance[2]
1	Tree Management	$ 0.083	$ 0.434	$ 0.352	$ 0.787
2	Generation Dam Safety	$ 0.256	$ 0.111	$ (0.145)	$ (0.007)
3	Network Operations Apprentice Program	$ 0.217	$ 0.245	$ 0.027	$ (0.140)
4	Cyber Security	$ 0.088	$ 0.264	$ 0.176	$ 0.426
5	Data Analytics	$ 0.109	$ -	$ (0.109)	$ (0.316)
6	Other	$ -	$ -	$ -	$ -
7	Total	$ 0.754	$ 1.054	$ 0.301	$ 0.750

Notes to Table:

[1] 2022 Formula O&M is the approved 2021 formula for incremental funding with Net Inflation factor applied (4.041%).
[2] Cumulative Forecast/Actual variance is the 2020, 2021 and 2022 Actual variance.

Overall, total actual spending in 2022 was $1.054 million, which is $0.301 million higher than the 2022 Formula O&M amount. Areas with notable variances include tree management, generation dam safety, cyber security and data analytics.

For tree management, FBC spent $0.352 million more than the formula amount to address an increased number of unhealthy trees as part of FBC's right-of-way management program.

For generation dam safety, FBC spent $0.145 million less than the formula amount primarily due to the completion of dam safety review activities in 2021. As explained in Section 6.2.1 of the Annual Review for 2023 Rates, FBC spent $0.199 million more than the formula amount in 2021 due to the continuation of dam safety review activities. The spending overall on these activities has been consistent with the formula amount, as the cumulative variance is only $0.007 million for the first three years of the MRP term (as shown in Table 6-3 above).

For cyber security, FBC spent $0.176 million more than the formula amount. The higher spending was for additional consulting resources in the following areas: an additional consulting resource to augment cybersecurity requirements due to additional threat management needs; emergency management consulting for emergency exercises; physical security threat intelligence services to manage security risk; and the use of consulting services to update the business continuity program.

In data analytics, FBC spent $0.109 million less than the formula amount in 2022 primarily due to labour savings from a delay in hiring. In 2022, the focus was on building solutions in business areas including providing enhanced reporting using dashboards. For further details, please refer to Section 1.4.2 of the Application.

For the first three years of the MRP, FBC spent $0.750 million more than the formula amount. Over the term of the MRP, FBC anticipates the total new/incremental spending required in the combined categories of System Operations, Integrity and Security will continue to be higher than the amount embedded in the formula. FBC will continue to manage this spending within its overall O&M spending envelope.

6.3 O&M EXPENSE FORECAST OUTSIDE THE FORMULA

In addition to FBC's formula O&M, FBC forecasts a number of O&M items outside of the formula annually, including pension and OPEB expense, insurance premiums, BCUC levies, and the cost of service associated with Clean Growth initiatives, such as Electric Vehicle (EV) charging stations, as well as the O&M impacts of any exogenous factor items. For 2024, FBC continues to include the incremental O&M resulting from the Mandatory Reliability Standards (MRS) Assessment Report No. 13 (AR13), which was approved for exogenous treatment in the Annual Review for 2022 Rates.

The 2024 amounts are shown in Table 6-4 below along with a comparison to 2023.

Table 6-4: 2024 Forecast O&M ($ millions)

Line No.	Description	Approved 2023	Projected 2023	Forecast 2024
1	Pension/OPEB (O&M Portion)	$ (1.297)	$ (1.297)	$ (2.532)
2	Insurance Premiums	2.457	2.507	2.678
3	BCUC Levies	0.385	0.385	0.458
4	Clean Growth Initiative - EV DCFC	0.219	0.181	0.310
5	Exogenous Factor - MRS	0.585	0.585	0.585
6	Total Forecast O&M	$ 2.349	$ 2.361	$ 1.499

Each of the items that is forecast outside of the formula is discussed below. Variances in pension and OPEB expense are captured in the Pension and OPEB Variance deferral account and variances in BCUC levies are captured in the BCUC Levies Variance deferral account. Variances in insurance premiums, the cost of service associated with EV charging stations, and exogenous factors are captured in the Flow-through deferral account.

6.3.1 Pension and OPEB Expense

Pension and OPEB expense for 2024 is based upon actuarial estimates using a range of assumptions as of December 31, 2022. In addition to O&M, pension and OPEB expense is embedded in capital expenditures, as shown in Table 6-5.

Table 6-5: Pension and OPEB Expense ($ millions)

Line No.	Description	Approved 2023	Projected 2023	Forecast 2024
1	O&M	$ (1.297)	$ (1.297)	$ (2.532)
2	Capital	1.888	1.888	1.875
3	Total Pension & OPEB Expense	$ 0.591	$ 0.591	$ (0.657)

The variance between the 2023 Approved/Projected and actual pension and OPEB expense is included in the Pension and OPEB Variance deferral account and amortized into rates over a three-year period, as approved by Order G-139-14.

The 2024 Forecast pension and OPEB expense is lower than 2023 Approved by $1.248 million. The difference is primarily due to the following factors:

- A decrease of approximately $1.7 million due to an increase in investment returns as a result of a higher balance of pension plan assets; and
- A decrease of approximately $0.3 million due to the US GAAP Pension & OPEB Transition Obligation non-rate base deferral account being fully amortized in 2023.

The above decreases are offset in part by:

- An approximate increase of $0.8 million in interest costs due to an increased discount rate, which is determined with reference to the market rate of interest on high-quality debt instruments at a point in time (a discount rate of 4.50 percent was used to determine the 2023 Approved expense compared to a discount rate of 5.25 percent used to determine the 2024 Forecast expense).

6.3.2 Insurance Premiums

The component of insurance expense tracked outside of formula O&M relates to the insurance premium expense allocated to FBC by Fortis Inc. as set out in Table 6-6 below.

Table 6-6: Insurance Premiums ($ millions)

Line No.	Description	Approved 2023	Projected 2023	Forecast 2024
1	Insurance Premiums	$ 2.457	$ 2.507	$ 2.678

FBC's annual insurance renewal occurs in July of each year. The 2023 Projected insurance premium expense of $2.507 million is $0.050 million higher than 2023 Approved, as it incorporates the first six months of FBC's actual July 2023 to June 2024 insurance renewals. The 2024 Forecast is $2.678 million, which is an increase of $0.171 million from 2023 Projected. The 2024 Forecast is calculated based on the six months of actual insurance premiums from July 2023 to June 2024 of $1.234 million, plus a 5 percent increase for the remaining six months, and the cost of fire fighting services FBC pays to the Province of $0.148 million.[28]

6.3.3 BCUC Levies

FBC's 2024 Forecast for BCUC levies is $0.458 million. The 2024 Forecast is based on Order G-134-23 for the BCUC's Fiscal 2023/24 year, which represents the best information available at

[28] $2.468 million/2 = $1.234 million. $1.234 million x 1.05 = $1.295 million. $1.234 million + $1.295 million + $0.148 million annual firefighting service fee = $2.678 million.

this time, as the BCUC levy calculation for its Fiscal 2024/25 year will not be available until early or mid 2024.

BCUC levies receive flow-through treatment, with annual variances between actual and forecast amounts in O&M expense being recorded in the BCUC Levies Forecast Variance deferral account and amortized over one year.

6.3.4 Clean Growth Initiative – Electric Vehicle (EV) DCFC Stations

As discussed in Section 3.6, FBC's EV DCFC stations are prescribed undertakings under section 5 of the GGRR[29] and the cost of service associated with EV DCFC stations is subject to flow-through treatment. Please refer to Table 3-5 in Section 3.6 which provides a summary of the EV DCFC stations' costs and revenues from 2022 Actual to 2024 Forecast.

Table 6-7 below provides a breakdown of the 2023 Approved, 2023 Projected and 2024 Forecast O&M expenses for FBC's EV DCFC service. The O&M expenses consist of network management, repairs and maintenance, inspection fees, FBC internal labour, and the electricity costs from third-party utilities (i.e., for stations in Grand Forks, Nelson, and Penticton).

Table 6-7: Clean Growth Initiative – EV DCFC Stations ($ millions)

Line No.	Description	Approved 2023	Projected 2023	Forecast 2024
1	Network Management	$ 0.047	$ 0.037	$ 0.050
2	Repairs and Maintenance	0.009	0.040	0.050
3	Inspection Fees	0.067	0.042	0.096
4	FBC Labour Costs	0.070	0.030	0.070
5	Third Party Utilities Costs	0.026	0.032	0.044
6	Total	$ 0.219	$ 0.181	$ 0.310

As shown in Table 6-7 above, the 2023 Projected O&M expense for the EV DCFC service is $0.038 million lower than 2023 Approved. This is primarily due to reduced FBC labour costs as a result of a vacancy, and reduced inspection fees as the new inspection agreement did not commence until mid-2023. These decreases are partially offset by the increase in repairs and maintenance costs as well as the increase in third-party utilities costs. The 2023 Projected repairs and maintenance costs are higher than 2023 Approved because the 2023 Approved amount did not account for the regular maintenance costs for stations where the warranty period expired, whereas the 2023 Projected amount includes an estimate of the ongoing regular maintenance costs at stations that are no longer covered by the vendor's warranty period. With regard to the increase in third-party utilities costs, this is primarily due to increased utilization at the stations located in the service areas of third-party utilities (i.e., Grand Forks, Nelson, and Penticton) as well as the rate increases by the third-party utilities.

[29] Order G-215-21 dated July 14, 2021.

The 2024 Forecast is $0.129 million higher than 2023 Projected. This is primarily due to increased inspection fees due to the full year impact of the inspection agreement, and higher FBC labour costs as FBC expects to fill the vacancy for 2024. Other drivers of the increase are higher FLO Global Management Service fees for network management, as well as an increase in third-party utilities costs due to a combination of expected increases in utilization of stations located in the service areas of the third-party utilities and the estimated increase in the rates of the third-party utilities.

6.3.5 MRS Incremental Operating Expenses

In the Annual Review for 2022 Rates Decision,[30] FBC received approval of exogenous factor treatment for the incremental O&M and capital costs associated with MRS AR13. As explained in the Annual Review for 2022 Rates proceeding, FBC expected to incur one-time costs in 2021 and 2022 related to the adoption of the standards in AR13 as well as ongoing incremental O&M expenses commencing in 2023[31].

Table 6-8 below provides the 2023 Approved, 2023 Projected, and 2024 Forecast of incremental O&M related to MRS AR13.

Table 6-8: Incremental O&M for MRS AR13 ($ millions)

Line No.	Description	Approved 2023	Projected 2023	Forecast 2024
1	Labour	$ 0.490	$ 0.490	$ 0.490
2	Non-Labour	0.095	0.095	0.095
3	Total	$ 0.585	$ 0.585	$ 0.585

The 2023 Projected O&M is consistent with 2023 Approved. For 2024, FBC is forecasting the same level of spending as in 2023. The spending is related to the ongoing efforts to maintain procedures and processes, hardware and software that address supply chain risk assessments, ongoing licensing and maintenance of the hardware and software, and the documentation to maintain compliance of AR13. As noted in the Annual Review for 2022 Rates, FBC expects these costs to continue in future years.

6.4 NET O&M EXPENSE

Net O&M expense is gross O&M less capitalized overhead. As approved by the BCUC in Order G-166-20, the capitalized overhead rate is set at 15 percent for FBC, unchanged from 2023. After capitalized overhead, the net O&M expense is $63.174 million in 2024.

[30] Decision and Order G-374-21, p. 21.
[31] Exhibit B-2, Annual Review for 2022 Rates Application, Section 12.2.1, pp. 103-104; Exhibit B-3, BCUC IR1 24.2.

6.5 SUMMARY

Overall, the increase in gross O&M expense from 2023 Approved to 2024 Forecast is 2.3 percent. Formula-driven O&M is increasing at a rate of 3.6 percent while O&M forecast outside the formula is decreasing by approximately 36.2 percent from 2023 Approved.

The capitalized overhead rate for 2024 remains unchanged from 2023.

7. RATE BASE

7.1 INTRODUCTION AND OVERVIEW

FBC forecasts its Rate Base to be $1.714 billion for 2024. Rate Base is comprised of mid-year net plant in service, work in progress not attracting AFUDC, unamortized deferred charges, working capital, and the utility plant acquisition adjustment.[32]

FBC's 2024 Rate Base includes the full-year impacts of the 2023 closing projected plant balances as well as the impact of the following amounts:

- Mid-year impact of regular capital additions, net of CIAC additions, of $97.783 million;
- Mid-year impact of plant depreciation, net of CIAC amortization, of $66.744 million; and
- Capital additions of CPCNs and other Major Projects totalling $5.500 million, as discussed in Section 7.3 below, which include:
    - Full-year impact of $2.769 million for the final capital expenditures and related AFUDC in 2023 for the Kelowna Bulk Transformer Additions (KBTA) Project; and
    - Full-year impact of $2.731 million for the final capital expenditures and related AFUDC in 2023 for the Corra Linn Dam Spillway Gates Replacement Project.

In addition, various changes in deferred charges, working capital and other items increase rate base by a net amount of $2.735 million in 2024.

Details of the 2024 Forecast plant balances can be found in Section 11, Schedules 5 through 9.

7.2 REGULAR CAPITAL EXPENDITURES

As part of the MRP Decision and Order G-166-20, FBC received the following approvals for capital expenditures:

- Approval of FBC's forecasts submitted for regular capital expenditures (i.e., growth, sustainment, and other) for the years 2020 through 2022; and
- Approval of several items to be forecast on an annual basis.

Further, as part of FBC's 2023 Annual Review Decision and Order G-382-22, and Reconsideration Decision and Order G-87-23, FBC received approval of its forecasts of regular capital expenditures for the years 2023 and 2024.

The components of FBC's 2024 regular capital expenditures are shown in Table 7-1 below.

[32] The utility plant acquisition adjustment relates to the 1982 purchase of Plants 2, 3, and 4 and is being amortized over a period of 64 years.

Table 7-1: Regular Capital Expenditures ($ millions)

Line No.	Description	Approved 2023	Projected 2023	Forecast 2024	Reference
1	Forecast Capital	$ 92.440	$ 92.440	$ 93.433	Table 7-2, Line 4
2	Flow-Through Capital	0.248	0.580	0.500	Table 7-3, Line 2
3	Total Gross Regular Capital	$ 92.688	$ 93.020	$ 93.933	Sum of Lines 1 & 2
4	Less CIAC	(11.628)	(11.623)	(7.539)	Section 11, Schedule 9, Line 2
5	Net Regular Capital	$ 81.060	$ 81.397	$ 86.394	Sum of Lines 3 & 4

FBC notes that, pursuant to Order G-135-23, FBC is directed to file a CPCN application for the Fruitvale Substation Project prior to the start of construction. This project was included in the approved regular capital expenditure forecasts for 2023 and 2024. As the Fruitvale Substation Project now requires a CPCN, FBC has removed the capital expenditures from the 2023 Approved, 2023 Projected, and 2024 Forecast regular capital amounts shown in Tables 7-1 and 7-2 (forecast regular capital of $1.087 million in 2023 and $7.021 million in 2024). These expenditures will now be treated in the same manner as FBC's other CPCN and Major Project capital expenditures. Please refer to Section 7.3 for further detail.

In the subsections below, FBC provides further details on its regular capital expenditures for 2024.

7.2.1 Approved Capital Expenditures

The level of forecast capital expenditures approved for 2024 by Orders G-382-22[33] and G-87-23[34] is shown in Table 7-2 below. As discussed above, following Order G-135-23, FBC removed the 2023 Approved, 2023 Projected and 2024 Forecast sustainment capital expenditures related to the Fruitvale Substation Project; therefore, the amounts shown in Table 7-2 exclude the Fruitvale Substation Project expenditures.

Table 7-2: Approved Capital Expenditures ($ millions)

Line No.	Description	Approved 2023	Projected 2023	Forecast 2024	Reference
1	Growth Capital	$ 30.072	$ 30.072	$ 24.568	Section 11, Schedule 4, Line 2
2	Sustainment Capital	44.710	44.710	51.652	Section 11, Schedule 4, Line 3
3	Other Capital	17.658	17.658	17.213	Section 11, Schedule 4, Line 4
4	Total	$ 92.440	$ 92.440	$ 93.433	Section 11, Schedule 4, Line 5

[33] FBC Annual Review for 2023 Rates Decision and Order G-382-22.
[34] FBC Reconsideration Decision and Order G-87-23 regarding the FBC Application for Reconsideration and Variance of Decision and Order G-382-22.

7.2.2 Flow-Through Capital Expenditures

FBC is afforded flow-through treatment for certain capital items due to a variety of factors, including their uncontrollable nature, because they drive incremental revenues, because they are related to Clean Growth initiatives, or because of the uncertainty in scope, costs and timing.

The amounts for 2024 are shown in Table 7-3 below along with a comparison to 2023.

Table 7-3: Flow-Through Regular Capital Expenditures ($ millions)

Line No.	Description	Approved 2023	Projected 2023	Forecast 2024	Reference
1	Clean Growth Initiative - EV DCFC	0.248	0.580	0.500	
2	Total Forecast Capital Expenditures	$ 0.248	$ 0.580	$ 0.500	Section 11, Schedule 4, Line 8

7.2.2.1 EV DCFC Stations

As discussed in Section 3.6, FBC's EV DCFC stations are prescribed undertakings under section 5 of the GGRR[35], and the cost of service associated with EV charging stations is subject to flow-through treatment. Please refer to Table 3-5 of Section 3.6 which provides a summary of the EV DCFC stations' costs and revenues from 2022 Actual to 2024 Forecast.

Table 7-3 above shows the EV DCFC stations capital expenditures for 2023 Approved, 2023 Projected, and 2024 Forecast. The 2023 Projected EV DCFC stations capital expenditures are $0.332 million higher than 2023 Approved, primarily due to unbilled charges from 2022 construction activities, which are related to the planned DCFC stations in Keremeos and Princeton that were identified in FBC's Revised and Updated Application for EV DCFC Service and approved by Order G-215-21.[36] The construction was completed in 2022, but FBC did not receive all invoices for the work until 2023.

The 2024 Forecast capital expenditures are related to the accessibility improvement work at FBC's existing EV DCFC sites that was started in 2023. In 2023, FBC is projecting to complete the improvement work at four sites (which was included as part of the 2023 Approved expenditures), while the remaining sites are expected to complete in 2024. As noted in the Annual Review for 2023 Rates, the scope of the improvements include new or additional lighting, as the stations are available for use 24 hours a day, and paving for wheelchair access to the charger.

FBC is not forecasting the construction of any additional stations in 2024 at this time; however, FBC will continue to monitor the station utilization and customer demand to determine if additional stations are warranted.

[35] Order G-215-21 dated July 14, 2021.
[36] FBC's Revised and Updated EV DCFC Service Application, Table 2-2, pp. 10-11.

7.3 MAJOR PROJECTS CAPITAL EXPENDITURES

Major Projects are capital expenditures that do not form part of regular capital spending as they are approved through a separate CPCN or other application. As part of the MRP Decision,[37] the BCUC approved the continuation of the current process of reviewing Major Projects outside of the proposed MRP and approved the continuation of the existing financial threshold for CPCNs of $20 million for FBC for the MRP term.

For 2024, FBC is not forecasting any capital expenditures related to Major Projects. However, FBC's 2024 Forecast rate base includes the full-year impact of capital additions related to the KBTA Project and the Corra Linn Dam Spillway Gate Replacement Project. FBC also provides a brief discussion on the Fruitvale Substation Project, as FBC is expecting to submit a CPCN application for this project in 2023. Each of these projects is described further below.

KBTA Project

The KBTA project was approved by Order C-4-20 and involves the installation of a third terminal transformer at the F.A. Lee Terminal Station, including the reconfiguration of the 138 kV bus into an industry standard ring bus configuration. The project is expected to complete in 2023 with an estimated final cost of $23.287 million, inclusive of AFUDC and cost of removal. A total of $19.941 million (plus $0.577 million of removal costs) were included in FBC's rate base on January 1, 2023, with the remaining $2.769 million expected to enter FBC's rate base on January 1, 2024.

Corra Linn Dam Spillway Gates Replacement Project

The Corra Linn Dam Spillway Gates Replacement Project was approved by Order C-1-17 and involves the replacement of 14 spillway gates and upgrades to the associated infrastructure. As explained in FBC's Reconsideration Application to the Decision and Order G-382-22 for the Annual Review for 2023 Rates, which was approved by Order G-87-23, the replacement of all spillway gates was complete in 2022 and the costs were included in FBC's rate base between 2018 and 2023, with the remaining close-out activities delayed to 2023. The close-out activities, including lighting, outstanding claims, and clean-up, are estimated to be approximately $2.731 million and are expected to be complete in 2023; therefore, the costs are forecast to enter FBC's rate base on January 1, 2024. The final project cost is expected to be $80.835 million, inclusive of AFUDC and removal costs.

Fruitvale Substation Project

The Fruitvale Substation Project was included as part of FBC's regular capital forecasts for 2023 and 2024 in the Annual Review for 2023 Rates (forecast regular capital of $1.087 million in 2023 and $7.021 million in 2024). FBC's 2023 and 2024 regular capital forecasts were approved as part of the BCUC's Decision and Order G-382-22. However, following a complaint regarding the location of the proposed substation in Fruitvale, the BCUC issued Order G-135-23 on June 9, 2023, directing FBC to file an application for a CPCN related to the proposed Fruitvale Substation

[37] MRP Decision and Order G-166-20, pp. 132-133.

Project. As discussed in Section 7.2, FBC has removed the 2023 and 2024 capital expenditures related to the Fruitvale Substation Project from regular capital, as the expenditures will now be treated in the same manner as FBC's other CPCN and Major Project capital expenditures. FBC expects to file an application for a CPCN for the Fruitvale Substation Project before the end of 2023.

7.4 2024 PLANT ADDITIONS

The 2024 Plant Additions are comprised of: (i) FBC's 2024 regular capital expenditures from Section 7.2; (ii) the Major Projects from Section 7.3 to the extent that portions of those projects are placed into service; (iii) the change in work in progress which adjusts for capital expenditures for projects that are in progress at year-end; (iv) AFUDC; and (v) overhead capitalized for the year. A reconciliation of capital expenditures to plant additions is shown below and is also provided in Section 11, Schedule 5.

Table 7-4: Reconciliation of 2024 Capital Expenditures to Plant Additions ($ millions)[38]

Line No.	Description		Forecast 2024	Reference
1	Forecast Capital Expenditures	$	93.433	Section 11, Schedule 5, Line 2
2	Flow-Through Capital Expenditures		0.500	Section 11, Schedule 5, Line 3
3	Total Gross Regular Capital Expenditures		93.933	Sum of Lines 1 and 2
4				
5	Capitalized Overhead		11.148	Section 11, Schedule 5, Line 16
6	AFUDC		0.241	Section 11, Schedule 5, Line 17
7	Change in Work in Progress		-	Section 11, Schedule 5, Line 19
8	Total Regular Additions to Plant		**105.322**	Sum of Lines 3 through 7
9				
10	Special Projects and CPCN			
11	Capital Expenditures		-	Section 11, Schedule 5, Line 22
12	AFUDC		0.001	Section 11, Schedule 5, Line 23
13	Change in Work in Progress		5.499	Section 11, Schedule 5, Line 25
14	Total Special Projects and CPCN Additions to Plant		**5.500**	Sum of Lines 11 through 13
15				
16	Total Plant Additions	**$**	**110.822**	Line 8 + Line 14

7.5 ACCUMULATED DEPRECIATION

Rate base includes both the accumulated depreciation on plant in service and accumulated amortization of CIAC. Both are increased through depreciation expense and decreased through retirements.

[38] Line 11 of Table 7-4 is zero because, as described in Section 7.3, there are no capital expenditures forecast in 2024 for the two approved CPCN Projects (i.e., the KBTA Project and the Corra Linn Dam Spillway Gates Replacement Project). Further, FBC will be filing for a CPCN related to the Fruitvale Substation Project in 2023, as such, FBC has not included the forecast capital expenditures related to this project.

The depreciation rates used for 2024, which were approved by Order G-166-20 and are based on FBC's most recent depreciation study, include the recovery of the estimated future costs of removal over the average service life of the assets (net salvage) in accumulated depreciation. Depreciation is calculated beginning January 1 of the year after the assets are placed in service, which is the treatment approved by Order G-139-14.

Based on calculating depreciation expense at these approved depreciation rates on the opening plant-in-service balance, the 2024 depreciation expense is calculated as $66.744 million.[39]

7.6 DEFERRED CHARGES

On May 3, 2017, the BCUC issued its Regulatory Account Filing Checklist.[40] The stated purpose of the checklist is to assist regulated entities when filing regulatory account requests and to facilitate an efficient review by the BCUC.

The checklist classifies deferral accounts as one of: (a) forecast variance account; (b) rate smoothing account; (c) benefit matching (capital-like) account; (d) retroactive expense account; or (e) other. In Section 11, Schedule 11, FBC has classified its rate base deferral accounts in accordance with this classification.

The 2024 Forecast mid-year balance of unamortized deferred charges in rate base for FBC is a debit of $51.287 million.

The 2024 debit balance is driven largely by the balance in the Demand Side Management (DSM) deferral account of $44.063 million.

Figure 7-1 provides the mid-year deferral account balances summarized by deferral account category.

[39] $72.053 million depreciation expense as shown in Section 11, Schedule 21, Line 2 less $5.309 million amortization of CIAC as shown in Section 11, Schedule 21, Line 8.
[40] BCUC Letter, Log No. 53608, Appendix B.

Figure 7-1: FBC Forecast Mid-Year Balances of Rate Base Deferral Accounts by Category

Based on the approved amortization and the opening balances of each deferral account, the amortization expense, including both rate base and non-rate base deferral accounts, is calculated to be a credit of $2.860 million,[41] which will be returned to customers through the proposed 2024 rates. The subsections below include a discussion on new rate base deferral accounts and changes or updates to existing rate base deferral accounts. For a discussion on non-rate base deferral accounts, please refer to Section 12.

7.6.1 New Deferral Accounts

FBC is seeking approval to create five new rate base deferral accounts in this Application:

- 2025 Multi-year Rate Plan (MRP) Application;
- 2024 Mandatory Reliability Standards Audit;
- PST Rebate on Select Machinery and Equipment;
- BC Cost of Living Credit; and
- Climate Change Operational Adaptation (CCOA) Plan.

Table 7-5 below addresses the considerations identified in the Regulatory Account Filing Checklist as they pertain to each deferral accounts requested. For a detailed description of each deferral account, please refer to Sections 7.6.1.1 to 7.6.1.5 below.

[41] Section 11, Schedule 21, Column 3, Sum of Lines 5 and 6.

Table 7-5: Deferral Account Filing Considerations

Item	Consideration	2025 MRP Application	2024 MRS Audit	PST Rebate on Select Machinery and Equipment	BC Cost of Living Credit	Climate Change Operational Adaptation Plan
I.	Indicate if the request is: (a) for a modification or a change in scope to an existing Commission approved regulatory account; or (b) to establish a new regulatory account.	The 2025 MRP Application is a new deferral account. Please refer to Section 7.6.1.1 for additional information.	The 2024 MRS Audit is a new deferral account. Please refer to Section 7.6.1.2 for additional information.	The PST Rebate on Select Machinery and Equipment is a new deferral account. Please refer to Section 7.6.1.3 for additional information.	The BC Hydro Cost of Living Credit is a new deferral account. Please refer to Section 7.6.1.4 for additional information.	The Climate Change Operation Adaptation Plan is a new deferral account. Please refer to Section 7.6.1.5 for additional information.
a)	If the request is for a modification or change in scope to an existing regulatory account, explain why the existing regulatory account is an appropriate account to use (specifically addressing the existing account's intended and approved purpose, mechanism for recovery, timeline for recovery and carrying costs).	N/A	N/A	N/A	N/A	N/A

Item	Consideration	2025 MRP Application	2024 MRS Audit	PST Rebate on Select Machinery and Equipment	BC Cost of Living Credit	Climate Change Operational Adaptation Plan
b)	If the request is for approval of a new regulatory account, state the purpose of the regulatory account and explain its intended use.	The requested account is a regulatory proceeding cost account, which is routinely sought by utilities to capture external costs related to the preparation, filing, and regulatory review of applications.	The requested account will capture periodic incremental costs of the MRS compliance audit.	The requested account will capture PST Rebates on Select Machinery and Equipment received from the Province of BC.	The requested account will capture the residual balance of the BC Cost of Living Credit.	The requested account will capture costs related to the development of the Climate Change Operational Adaptation Plan.
II.	Propose a term (i.e., length of time) that the regulatory account should be approved for and explain why that term is appropriate.	The term of the account encompasses the preparation and filing of the relevant regulatory application and its review by the BCUC.	The term of the account encompasses the required time to conduct the audit.	The term of the account encompasses the required time for the Province of BC to approve the qualified claim filed by FBC and issue the refund payment.	The term of the account encompasses the time required to distribute the credits to all applicable customers.	The term of the account encompasses the time required for the development of the CCOA Plan and subsequent business cases as discussed in the 2021 Long Term Electric Resource Plan (LTERP).
III.	Identify any alternate treatments that were considered, including an overview of what the accounting treatment would be in the absence of approval of the request to establish a regulatory account, and explain why these alternate treatments may not be appropriate.	In the absence of deferral accounts for regulatory proceedings, the costs of regulatory proceedings would have to be forecast as an O&M expense (outside of the MRP index-based O&M as regulatory proceeding costs are not included in Base O&M Expense) and trued up annually by way of the	In the absence of a deferral account, the audit costs would have to be forecast as an O&M expense (outside of the MRP index-based O&M, as the costs are not included in Base O&M Expense) and trued up annually by way of the Flow-Through deferral account. FBC considers this to be a more cumbersome	In the absence of a deferral account, the rebate would be recorded as an offset in the applicable accounts where the original PST costs were recorded, whether those accounts were O&M or capital. FBC considers this to be a less transparent way of recording the rebates as it is the cost-of-	In the absence of a deferral account, the credit would remain in an FBC liability account until the residual balance is distributed through inquiries. FBC does not expect there will be enough inquiries to distribute the total residual balance. Eventually, the residual balance would be recorded as	In the absence of a deferral account, the costs would have to be forecast as an O&M expense (outside of the MRP index-based O&M, as the costs are not included in Base O&M Expense) and trued up annually by way of the Flow-Through deferral account. FBC considers this to be a more cumbersome

Item	Consideration	2025 MRP Application	2024 MRS Audit	PST Rebate on Select Machinery and Equipment	BC Cost of Living Credit	Climate Change Operational Adaptation Plan
		Flow-Through deferral account. FBC considers this to be a more cumbersome and less efficient means of accounting for regulatory proceeding costs. It is accepted regulatory practice to defer the costs of regulatory applications for review and recovery following the regulatory review of the application itself. Review and recovery after the completion of the regulatory process allows for more transparency as the history of the costs is simpler to track and report.	and less efficient means of managing the audit costs. In addition, the use of a deferral account permits multi-year cost recovery, which is consistent with the three-year period between audits, as opposed to recovery in a single year.	service impacts of the amounts credited to capital that would be returned to customers over a longer timeframe, rather than the rebate amount itself over one year as proposed using the deferral account approach.	income, and FBC would need to request a method of returning that income to customers, either via the Flow-Through deferral or by including the amount in its revenue requirements. The use of a deferral account permits the remaining credits to be used to benefit all customers, in a timely and efficient manner, consistent with the purpose of the credit.	and less efficient means of managing these costs.

Item	Consideration	2025 MRP Application	2024 MRS Audit	PST Rebate on Select Machinery and Equipment	BC Cost of Living Credit	Climate Change Operational Adaptation Plan
IV a)	Address: whether, or to what extent, the item is outside of management's control;	Regulatory proceeding cost accounts are necessary because the number and type of regulatory proceedings can vary significantly by year. Further, once a regulatory proceeding is identified, the costs of that proceeding cannot be accurately forecast by the utility given that they can vary substantially, are not known at the time of making the regulatory account request, are unique to the circumstances for each application, may change as the regulatory review process unfolds, and are dependent on factors not within the utility's control. Factors not within the control of the utility include the regulatory process determined by the BCUC and the degree of involvement of interveners.	Compliance audits of MRS are conducted every three years. The scope and complexity of audits varies depending on the standards under review and are not within the control of the Company.	The final amount of PST rebates claimed by FBC are subject to approval by the Province of BC.	The amount of credit available to FBC and the eligibility criteria was determined by the Province of BC.	As a result of the ongoing impacts of global climate change, FBC has determined it is imperative to address the risks of climate change risk on its system. Therefore, although direct costs are within Management's control, the need to incur these costs is considered necessary.

Item	Consideration	2025 MRP Application	2024 MRS Audit	PST Rebate on Select Machinery and Equipment	BC Cost of Living Credit	Climate Change Operational Adaptation Plan
b)	the degree of forecast uncertainty associated with the item;	Refer to IV. a). FBC forecasts additions to the deferral account based on the expected type of review process and degree of intervener involvement. Actual costs are recorded in the account so that actual, not forecast, costs are recovered in rates.	Refer to IV. a). FBC forecasts additions to the deferral account based on past audit experience. Actual costs are recorded in the account so that actual, not forecast, costs are recovered in rates.	Refer to IV. a). FBC forecasts additions to the deferral account based on the rebates received to date plus those claimed and expected to be received. Actual expected rebates will be recorded in the account so that actual, not forecast, rebates are returned in rates.	Refer to IV. a). FBC forecasts additions to the deferral account based on the residual balance of credits remaining to date. The actual residual balance, inclusive of further eligible inquiries, will be recorded in the account so that the actual, not forecast, remaining credits are returned in rates.	Refer to IV. a). FBC forecasts additions to the deferral account based on expected incremental resources required to complete the plan. Actual costs are recorded in the account so that actual, not forecast, costs are recovered in rates.
c)	the materiality of the costs	The number and size of regulatory proceedings vary from year to year, and represent costs not included in Base O&M for the purpose of determining formula O&M Expense under the MRP. Please refer to Section 7.6.1.1 for additional information.	Audit preparation and participation impacts many individuals and business units and is not manageable within FBC's formula O&M Expense. FBC expects costs related to the MRS Audit of approximately $0.375 million ($0.274 million after-tax). Please refer to Section 7.6.1.2 for additional information.	FBC expects rebates of approximately $0.591 million ($0.431 million after-tax). Please refer to Section 7.6.1.3 for additional information.	FBC expects the remaining credit to be approximately $0.507 million ($0.370 million after-tax). Please refer to Section 7.6.1.4 for additional information.	FBC expects costs related to the CCOA Plan of approximately $0.225 million ($0.164 million after tax) in 2023 and a further $0.192 million ($0.140 million after-tax) in 2024. Please refer to Section 7.6.1.5 for additional information.

Item	Consideration	2025 MRP Application	2024 MRS Audit	PST Rebate on Select Machinery and Equipment	BC Cost of Living Credit	Climate Change Operational Adaptation Plan
d)	any impact on intergenerational equity	Generally, FBC recovers the costs of regulatory proceedings over the period of time related to the application, which serves to match the costs and benefits. There are no intergenerational inequities inherent in this practice.	FBC expects to recover the audit costs over the period of time between audits, which serves to match the costs and benefits. There are no intergenerational inequities inherent in this practice.	FBC expects to return the rebates over the same period of time as the qualifying period to make the PST rebate claims. There are no intergenerational inequities in this practice.	FBC expects to return the remaining credit over the same period of time as the credit is made available by the Province of BC. There are no intergenerational inequities in this practice.	FBC expects to recover the costs of the CCOA Plan over the period of time required to develop the plan and subsequent business cases as outlined in the 2021 LTERP. There are no intergenerational inequities inherent in this practice.
V.	Classify the regulatory account as either: (a) forecast variance account; (b) rate smoothing account; (c) benefit matching account; (d) retroactive expense account; or (e) other.	FBC generally classifies regulatory proceeding accounts as benefit matching accounts since the costs are recovered over the period of time related to the applications, which serves to match the costs and benefits of the application.	The account is classified as a benefit matching account since the costs will be recovered over the period of time between audits, which serves to match the costs and benefits of the audit.	The account is classified as “other”.	The account is classified as “other”.	The account is classified as “other”.
VI.	Identify if the regulatory account is a cash or non-cash account.	Regulatory proceeding cost accounts are cash accounts.	The MRS Audit deferral account is a cash account.	The PST Rebate on Select Machinery and Equipment is a cash account.	The BC Cost of Living Credit deferral account is a cash account.	The Climate Change Operational Adaptation Plan deferral account is a cash account.

Item	Consideration	2025 MRP Application	2024 MRS Audit	PST Rebate on Select Machinery and Equipment	BC Cost of Living Credit	Climate Change Operational Adaptation Plan
VII.	Specify what additions to the regulatory account are being requested (i.e. type and amount of additions), including whether the account is intended to capture additions for a specific period of time or on an ongoing basis.	Eligible costs include the BCUC's direct costs, notice publication costs, fees for consultants or experts, external legal counsel fees, courier and miscellaneous administrative costs, and participant assistance cost awards incurred in the preparation, filing and regulatory review of the applications. Regular labour and staff expenses related to regulatory applications are included in formula O&M Expense.	Eligible costs are incremental to ongoing MRS expenses and include labour, consulting and miscellaneous expenses not included in formula O&M Expense.	PST Rebates received from the Province of BC for claims filed by FBC for the qualifying period. Please refer to Section 7.6.1.3 for additional information.	The remaining credit is the total funds received by FBC less any credit already applied to customer bills as of June 2023. FBC will continue to capture any credits provided to customers from eligible inquiries for the credit. Please refer to Section 7.6.1.4 for additional information.	Eligible costs include fees for consultants required for the development of the plan.
VIII.	Propose a mechanism for recovery (e.g. how the balance in the regulatory account will be recovered or refunded to ratepayers) and explain why it is appropriate.	Costs are recovered in revenue requirements by way of amortization expense.	Costs are recovered in revenue requirements by way of amortization expense.	Rebates will be refunded in revenue requirements by way of amortization expense.	Credits will be refunded in revenue requirements by way of amortization expense.	Costs are recovered in revenue requirements by way of amortization expense.

Item	Consideration	2025 MRP Application	2024 MRS Audit	PST Rebate on Select Machinery and Equipment	BC Cost of Living Credit	Climate Change Operational Adaptation Plan
IX.	Propose a timeline for recovery (e.g. the period over which the regulatory account balance is either collected or refunded; also referred to as the amortization period) and explain why it is appropriate.	Generally, FBC proposes to amortize the costs of regulatory proceedings over the period of time related to the application, which serves to match the timing of costs and benefits. Please refer to Sections 7.6.1.1 for additional information.	FBC proposes to amortize the costs over three years beginning January 1, 2024, to reflect the period until the next audit. Recovery of the costs over the period of time between audits serves to match the costs and benefits of the audit. Please refer to Section 7.6.1.2 for additional information.	FBC proposes to refund the rebates over one year beginning January 1, 2024, to match the approximate qualifying period of eligible PST paid on purchases. Please refer to Section 7.6.1.3 for additional information.	FBC proposes to refund the remaining credits over one year beginning January 1, 2024. Please refer to Section 7.6.1.4 for additional information.	FBC proposes to amortize the costs over four years beginning January 1, 2024 to reflect the CCOA Plan timeline discussed in the 2021 LTERP. Please refer to Section 7.6.1.5 for additional information.
X.	Propose a carrying cost for the balance in the regulatory account and explain why it is appropriate.	Rate base deferral accounts are included in rate base and therefore, implicitly financed using the weighted average cost of capital (WACC).	Rate base deferral accounts are included in rate base and therefore implicitly financed using the weighted average cost of capital (WACC).	Rate base deferral accounts are included in rate base and therefore implicitly financed using the weighted average cost of capital (WACC).	Rate base deferral accounts are included in rate base and therefore implicitly financed using the weighted average cost of capital (WACC).	Rate base deferral accounts are included in rate base and therefore implicitly financed using the weighted average cost of capital (WACC).
XI.	Outline a recommended regulatory process for the Commission's review of the application.	The proposed deferral account can be reviewed as part of the present proceeding. Deferral account approvals and disposition are generally determined in revenue requirement proceedings.				

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7.6.1.1 2025 Multi-Year Rate Plan (MRP) Application

FBC's current Multi-year Rate Plan (MRP) approved by Order G-166-20 will end in 2024. FBC has started developing its next rate plan and expects to file this rate plan with the BCUC in early 2024. FBC will incur regulatory costs related to the development of the application and is requesting approval to establish a rate base deferral account to capture these costs, which will include BCUC costs, participant funding costs, external legal fees, expert/consulting costs, notice publication costs, and miscellaneous facilities, stationery, and supplies costs. FBC forecasts costs of $0.350 million ($0.256 million after-tax) in 2023 and $1.200 million ($0.876 million after-tax) in 2024. Actual costs will vary depending on how the application progresses and will be confirmed after the regulatory process is completed.

FBC is only requesting approval to establish this deferral account. FBC will propose an amortization period for the deferral account in a future rate-setting application (i.e., subsequent to the completion of the 2025 MRP application proceeding).

7.6.1.2 2024 Mandatory Reliability Standards (MRS) Audit

FBC's triennial MRS compliance audit is scheduled to occur in 2024. This audit will be performed by the administrator of the BC MRS Program, the Western Electricity Coordinating Council (WECC), and will include a review, at minimum, of all applicable reliability standards identified in the Actively Monitored List. This will include Critical Infrastructure Protection (CIP) and Operations and Planning (O&P) standards. Eligible costs are incremental labour and expenses directly caused by the periodic audit and therefore not included in Formula O&M Expense. Based on previous audits, FBC forecasts costs of $0.375 million before tax ($0.274 after tax) in 2024.

FBC is requesting approval to establish a rate base deferral account to capture the costs related to the 2024 MRS Audit. Further, FBC is proposing to amortize these costs over three years beginning January 1, 2024. This amortization period is appropriate as it reflects the period until the next MRS triennial audit.

7.6.1.3 PST Rebate on Select Machinery and Equipment

The BC PST Rebate on Select Machinery and Equipment is a provincial government program to help corporations recover from the financial impacts of the COVID-19 pandemic. Eligible businesses can receive as a rebate the PST paid on purchases of specified equipment and software during the qualifying period between September 17, 2020 and March 31, 2022.

FBC is eligible to claim a BC PST Rebate on Select Machinery and Equipment on capital purchases of software and equipment and has filed for these rebates for the qualifying periods as set out by the Province of BC. To date, FBC has received $0.029 million ($0.021 million after-tax) in rebates and expects additional rebates of approximately $0.562 million ($0.410 million after-tax) to be received by December 31, 2023.

FBC is requesting approval to establish a rate base deferral account to capture the PST Rebates on Select Machinery and Equipment received from the Province of BC. Further, FBC is proposing to amortize these rebates to customers over one year beginning January 1, 2024, to match the approximate qualifying period of eligible PST paid on purchases.

7.6.1.4 BC Cost of Living Credit

On November 18, 2022, the Province of BC issued OIC 571/2022[42] for a one-time cost-of-living credit to all eligible residential and commercial electricity customers through a BC Hydro bill credit, including those who receive their electricity service from FBC or a municipal utility.

FBC received funds through BC Hydro for applying the credits to all eligible residential electricity customers in the amount of a one-time $100 cost-of-living credit and to all eligible commercial electricity customers as a one-time bill credit calculated based on their prior year electricity consumption.

FBC received a total of $23.816 million and applied $23.290 million of credits to all eligible customers as of March 10, 2023. In addition to the bill credits applied to eligible customers, FBC has committed to provide credits to customers if/when a customer inquires about such credits to FBC (and if the customer is determined to be eligible)[43]. Between March 10, 2023 and May 31, 2023, FBC received a total of six inquiries (three residential and three commercial customers), resulting in a further $0.019 million of credits applied. The total credits applied to eligible customers as of June 10, 2023 are therefore $23.309 million, with $0.507 million ($0.370 million after-tax) of residual credits which FBC proposes to include as a credit amortization (i.e., return to all customers) in 2024 rates.

FBC requested and received confirmation from the Ministry of Energy, Mines and Low Carbon Innovation (EMLI) that there is no expectation or requirement for FBC to return the residual credits to either BC Hydro or the Province of BC. Furthermore, EMLI agreed that the remaining funds could be used to benefit all FBC customers through rates, which is consistent with the purpose of the bill credits. As such, FBC is requesting approval in this Application to establish a rate base deferral account to capture the residual balance of the BC Cost of Living Credit and to amortize the residual credits to customers through rates over a one-year period beginning January 1, 2024.

As agreed with EMLI, FBC will continue to field inquiries from customers and will provide bill credits to customers that are determined to be eligible. As noted above, FBC only received a total of six inquiries from March to May 2023 and has received no inquiries since then. As such, FBC is expecting a very limited number of inquiries to occur in the remaining months of 2023 and into 2024. However, should any further bill credits be issued to eligible customers in 2023 or 2024, FBC will record these issued amounts in the deferral account. If there is any remaining balance

[42] https://www.bclaws.gov.bc.ca/civix/document/id/oic/oic_cur/0571_2022.

[43] OIC 571/2022 sets out the eligibility criteria which defined that customers must be a customer and receiving service on October 1, 2022. Due to the timing lapse between October 1, 2022 and when the credits are distributed starting from December 2022 to March 2023 (the credit was announced by the Province of BC on November 18, 2022), customers could be connecting to and/or leaving FBC's system, potentially resulting in eligible customers not receiving the bill credit. As such, FBC agreed to field inquiries and continue to pay out any eligible credits.

(credit or debit) at the end of 2024, FBC will amortize the remaining balance into rates in the subsequent year (i.e., 2025).

7.6.1.5 Climate Change Operational Adaptation (CCOA) Plan

As discussed in FBC's most recent Long Term Electric Resource Plan (2021 LTERP) accepted by Order G-380-22, the threat that climate change presents to FBC infrastructure and operations is a continuing reality that FBC is taking seriously; accordingly, FBC is developing a roadmap for climate change adaptation.[44] FBC's Climate Change Operational Adaptation (CCOA) Plan focuses on addressing the climate change risks associated with five hazards: wildfires, flooding, extreme temperatures, snowstorms, and windstorms. During the initial phase of the CCOA Plan, FBC is working with consultants to identify assets vulnerable to each hazard, define the current and future risk profiles of the vulnerable assets due to these hazards, and propose adaptation strategies. These strategies may consist of, but are not limited to, system hardening, asset replacement, or modification of design standards. Future phases will apply these results and strategies to existing assets to determine whether risk reduction projects will be required.

FBC is requesting approval to establish a rate base deferral account to capture the costs related to the CCOA Plan. FBC forecasts costs of $0.225 million ($0.164 million after-tax) in 2023 and a further $0.192 million ($0.140 million after-tax) in 2024. The costs are primarily related to the resources required to develop the roadmap for climate change adaptation and, stemming from the roadmap, develop the business cases for the five key hazard areas (i.e., wildfires, flooding, extreme temperatures, snowstorms and windstorms). FBC is proposing to amortize these costs over four years beginning January 1, 2024. This period aligns with the CCOA Plan timeline discussed in the 2021 LTERP, which states that the development of the CCOA Plan and subsequent business cases would occur between now and 2027. FBC will continue to provide updates on the progress of the CCOA Plan and the deferral account in future annual reviews or revenue requirement applications.

7.6.2 Existing Deferral Accounts

In the discussion below, FBC provides information on one existing deferral account.

7.6.2.1 Princeton Office Disposition Deferral Account

On January 24, 2023, pursuant to Order G-14-23, FBC was approved to sell the Princeton Office Properties, consisting of the land and buildings located on Bridge Street in Princeton, BC, to the Town of Princeton. FBC was also approved to establish the Princeton Office Disposition non-rate base deferral account to capture the net gain on the sale, and to transfer the balance in the non-rate base deferral account to a rate base deferral account on January 1, 2024 and commence amortization of the deferral account over one year in 2024. FBC was directed to provide details

[44] FBC 2021 LTERP Application, p. 140; Exhibit B-2, BCUC IR1 24.4.

on the final balance in the Princeton Office Disposition deferral account in the Annual Review for 2024 Rates.

FBC received written notification of the removal of the Buyer's Subject Conditions on February 10, 2023, and on March 13, 2023, the sale of the Princeton Office Properties was fully completed. The final projected ending balance of the deferral account (i.e., projected to the end of 2023) is approximately $0.406 million, and this credit amount has been included in the 2024 revenue requirements and rates.

Please refer to Table 7-6 below for a breakdown of the net gain on the sale of the Princeton Office Properties. FBC notes that the estimated net gain on sale at the time of filing the Princeton Office Properties Application was $0.346 million. The difference between the original estimate and the final projected ending balance is solely due to a difference in the net book value of the land and building. When preparing this Application, FBC discovered that it incorrectly calculated the accumulated depreciation on the building at the time of filing the Princeton Office Properties Application. FBC has now corrected this error and, as a result, the net gain on sale to be provided to customers is higher than originally forecast in the Princeton Office Properties Application.

Table 7-6: Breakdown of Final Net Gain on Sale of the Princeton Office Properties

		$ millions
Sales Proceeds		0.474
Less:	Net Book Value of Land and Building	(0.041)
	Disposal Costs	(0.019)
	Taxes Payable	(0.008)
Gain on Sale		**0.406**

7.7 WORKING CAPITAL

The working capital component of rate base is comprised of cash working capital and other working capital.

Cash working capital is defined as the average amount of capital provided by investors in the Company to bridge the gap between the time expenditures are required to provide service (expense lag) and the time collections are received for that service (revenue lag). The cash working capital requirements that have been included reflect the most recent Lead Lag Study results, as approved through Order G-166-20.

Other working capital includes customer (DSM) loans, employee loans and withholdings, and inventory of materials and supplies. 2024 amounts are forecast based on 2022 Actual levels.

7.8 SUMMARY

FBC's rate base includes the impact of regular and Major Project capital expenditures, adjusted for work-in-progress, AFUDC and overheads capitalized. FBC has provided forecasts for all of its

rate base deferral accounts in the financial schedules included in Section 11. In Section 7.6.1, FBC requested approval of five new deferral accounts; and in Section 7.6.2, FBC discussed one existing deferral account. Finally, the rate base includes cash and other working capital.

8. FINANCING AND RETURN ON EQUITY

8.1 INTRODUCTION AND OVERVIEW

FBC has prepared this Application using a capital structure of 60 percent debt and 40 percent equity and a Return on Equity (ROE) of 9.15 percent, as approved by Orders G-129-16 and G-47-14. FBC's ROE is set at a premium of 40 basis points over the benchmark ROE, which is the ROE approved for FEI. FBC is currently awaiting a decision on Stage 1 of the BCUC-initiated Generic Cost of Capital (GCOC) proceeding which it expects to be issued in the upcoming months. FBC will provide an update to its rate calculations as part of an Evidentiary Update subsequent to the GCOC decision being issued.

The 2024 Forecast for financing costs, including the interest expense on issued long- and short-term debt and on new issuances that are forecast, has been updated as described in Section 8.3 below. Based on the updated financing costs, FBC's AFUDC rate for 2024 (which is equal to its after-tax weighted average cost of capital) is 5.75 percent.[45] Any variances from interest rates used to set rates, and any variances in interest resulting from items subject to flow-through in the Flow-through deferral account, will be flowed through to customers. All other differences in interest expense will affect the achieved ROE and be subject to earnings sharing.

8.2 CAPITAL STRUCTURE AND RETURN ON EQUITY

The Company finances its investment in rate base assets with a mix of debt and equity, as approved by the BCUC from time to time. Pursuant to Order G-47-14, FBC used the currently approved capital structure of 60.0 percent debt and 40.0 percent equity, with an equity risk premium of 40 basis point over the benchmark ROE, which was set at 8.75 percent by Order G-129-16, effective January 1, 2016, to calculate rates in this Application.

8.3 FINANCING COSTS

Debt financing costs include the borrowing costs on issued debt as well as on new issuances that are forecast. Debt consists of both long- and short-term debt.

8.3.1 Long-Term Debt

FBC is both a private and public issuer of long-term debt. FBC plans to issue additional long-term debt of approximately $100 million in April 2024 and will use the funds to repay existing indebtedness and finance the Company's capital expenditure program. The 2024 debt issuance is reflected in the financial schedules at a rate of 4.90 percent.[46] The exact timing, amount and rate of the 2024 issuance will depend on future market conditions and capital expenditure

[45] As part of the Evidentiary Update, FBC will update the AFUDC rate for 2024 to reflect any changes resulting from the GCOC decision.
[46] Section 11, Schedule 27, Line 9.

requirements. Variances in interest expense related to the timing and amount of the issuances of the debt or the rates at which they are issued will be captured in the Flow-through deferral account.

8.3.2 Short-Term Debt

FBC obtains short-term funding primarily through the issuance of commercial paper to Canadian institutional investors. FBC backstops the commercial paper issuances by maintaining a $150 million committed credit facility that matures in April 2027.[47] This facility is also used to issue letters of credit. The credit facility, along with a $10 million overdraft facility, provides FBC with short-term liquidity to fund its capital program and working capital requirements.

8.3.3 Forecast of Interest Rates

FBC uses interest rate forecasts to estimate future interest expense. Forecasts of Treasury Bills and benchmark Government of Canada Bond interest rates are used in determining the overall interest rates for short-term debt and for rates on new issues of long-term debt, respectively. The forecasts are based on available projections made by Canadian Chartered banks.

Credit spreads on new long-term debt are based on current indicative rates, on the assumption that the current credit ratings of FBC are maintained.

FBC's short-term borrowing rate is based on the rate at which it issues commercial paper. Since commercial paper issuance rates are not forecast by economists, a forecast needs to be derived by FBC. The forecast is based on the historical differential between the Canadian Deposit Overnight Rate (CDOR) and the rate obtained by FBC under its commercial paper program. CDOR is used because FBC's short-term borrowings under its credit facility are priced based on CDOR and therefore CDOR is tracked relative to FBC's commercial paper borrowings. As CDOR is not forecast by economists, FBC must first obtain the 3-Month T-Bill rate forecast and then convert it to a CDOR forecast. FBC does this by taking the 3-year historical spread between CDOR and the 3-month T-Bill rate. Then, to derive the short-term borrowing rate forecast, FBC adjusts the CDOR forecast with the historical spread between CDOR and rates of issuances under its commercial paper program.

The 3-month T-Bill forecast for 2024 is 4.27 percent, which is an increase from the 3.14 percent approved in 2023. FBC continues to face a rising interest rate environment due to high inflation and the Bank of Canada continuing to raise its policy interest rate in an attempt to slow economic growth and reduce core inflation. While the inflation in Canada eased to 3.40 percent in May 2023 from a high of 8.10 percent from a year ago, the downward movement was driven largely by lower energy prices rather than easing underlying inflation. The Bank of Canada's latest interest rate

[47] On July 14, 2023, FBC filed an application with the BCUC to increase the principal amount of the credit facility from $150 million to $200 million and to extend the maturity date of the credit facility to April 2028. If this application is approved, FBC will include any related impacts in the Evidentiary Update which FBC expects to file subsequent to the GCOC decision being issued.

increase in July 2023 brings the overnight rate to 5.0 percent, which was the tenth interest rate increase since March 2022 when the overnight rate was at 0.25 percent.

For 2024, FBC forecasts higher Other Financing Fees than the 2023 Approved amount due to higher customer deposit interest, resulting from a higher prime rate in 2023. Other Financing Fees include the fees that FBC incurs for its letters of credit under the credit facility, as well as interest paid on customer deposits. The short-term borrowing rate forecast is shown in Table 8-1 below.

Table 8-1: Short Term Interest Rate Forecast

FBC Short Term Interest Rate	Approved 2023	Projected 2023	Forecasted 2024
3-Month T-Bill Rate [1]	3.14%	5.04%	4.27%
Spread to CDOR	0.36%	0.41%	0.41%
CDOR Rate	3.50%	5.45%	4.69%
Spread to CP	-0.36%	-0.47%	-0.47%
CP Dealer Commission	0.10%	0.10%	0.10%
ST Interest Rate on Credit Facilities	**3.24%**	**5.09%**	**4.32%**
Fixed Financing Fees [2]			
Standby fee on Undrawn Credit [3]	0.44%	0.24%	0.32%
Renewal Fee on Undrawn Credit	0.12%	0.07%	0.09%
Other Financing Fees	0.44%	0.34%	0.49%
ST Interest Rate on Fixed Financing Fee	**1.00%**	**0.64%**	**0.89%**
FBC Short Term Rate	**4.24%**	**5.73%**	**5.21%**

Notes to Table:

[1] 3-month T-Bill rate for 2024 is a weighted average rate based on forecasts provided by Canadian Chartered banks in July 2023.

[2] Fixed financing fees represent the costs of maintaining the credit facility and letter of credit facility, which are fixed fees incurred regardless of whether FBC draws from the credit facility. The fees have been converted into a short-term rate for forecast purposes.

[3] A standby fee of 20 bps is charged on undrawn credit facility amounts, which would change if credit facility amounts are drawn through banker acceptances or prime loans. However, the forecast assumes FBC will borrow through commercial paper and will not change the undrawn credit facility fee percentage.

4. Other financing fees include commercial paper issuance fees, letter of credit fees, customer deposit interest expense and miscellaneous bank administration costs. The letter of credit fees, customer deposit interest and miscellaneous bank administration costs are incurred regardless of whether FBC draws from the credit facility.

As noted above, FBC's interest rate forecasts are based on CDOR. An indirect result of the cessation of the publication of the London Interbank Offered Rate (LIBOR) is that Canada is planning to discontinue using CDOR as a risk-free rate benchmark for financial instruments in multiple asset classes. This will impact FBC's credit facility agreement as Refinitiv Benchmark Services (UK) Limited (RBSL), CDOR's regulated administrator, announced that CDOR will cease to be published after June 28, 2024.[48] The Canadian Alternative Reference Rate Working Group (CARR) was established to coordinate the transition to a new risk-free rate benchmark. In January

[48] https://www.bankofcanada.ca/markets/canadian-alternative-reference-rate-working-group/.

2023, CARR announced a development of a Term Canadian Overnight Repo Rate Average (Term CORRA), a risk-free interest rate benchmark for one- and three-month terms. Term CORRA is expected to replace CDOR and will become available in the latter half of 2023. As the Term CORRA rate is not yet available, FBC continues to use the CDOR methodology, consistent with its previous Annual Reviews, to forecast the short-term interest rate for 2024.

8.3.4 Interest Expense Forecast

The interest expense forecast reflects FBC's existing and forecast borrowing costs on long- and short-term debt.

Short-term interest expense is determined by applying the forecast short-term debt rate to the estimated short-term debt balance. Long-term debt interest expense is determined using the straight-line method by multiplying the average balance of the specific debenture by the debt coupon rate, or forecast coupon rate, if it is a new issue. The 2024 long-term debt schedule for FBC can be found in Section 11, Schedule 27.

8.3.5 Allowance for Funds Used During Construction (AFUDC)

FBC applies AFUDC to projects that are greater than three months in duration and greater than $100 thousand. Based on the above information, FBC's AFUDC rate for 2024 (which is equal to its after-tax weighted average cost of capital) is 5.75 percent. The calculation of the rate is shown in the following table.

Table 8-2: Calculation of AFUDC Rate for 2024

Description	Weight	Pre-Tax Rate	After-Tax Rate	Earned Return
Short Term Debt	5.46%	5.21%	3.80%	5.21%
Long Term Debt	54.54%	4.72%	3.45%	4.72%
Common Equity	40.00%	12.53%	9.15%	9.15%
Weighted Average	100.00%	7.87%	5.75%	6.52%

8.4 SUMMARY

FBC's equity financing and ROE have been forecast for 2024 at the same percentages as by Orders G-47-14 and G-129-16. FBC's debt financing costs on rate base are primarily determined by embedded rates on long-term debt, and to a lesser degree by short-term debt rates; the embedded rate on long-term debt is forecast to decrease in 2024 compared to 2023 (4.72 percent forecast for 2024 compared to 2023 Approved of 4.78 percent).

9. TAXES

9.1 INTRODUCTION AND OVERVIEW

This section discusses FBC's forecasts of property taxes and income tax which have been forecast on a basis consistent with prior years. In 2024, property taxes are forecast to increase by $0.313 million (1.7 percent) from 2023 Approved, while income tax is forecast to increase by $4.002 million (65.9 percent) compared to 2023 Approved.

9.2 PROPERTY TAXES

The 2024 Forecast of property taxes is approximately $18.573 million and is based on the Company's forecasts of assessed values of taxable assets, mill rates and taxes from revenues earned from electricity consumed within municipalities. A breakdown of property taxes by asset type is provided in Table 9-1 below.

Table 9-1: Property Taxes ($ millions)

Line No	Description	Approved 2023	Projected 2023	Forecast 2024
1	Generation Plant	$ 3.253	$ 3.201	$ 3.259
2	Transmission and Distribution	7.189	7.104	7.317
3	Substation Equipment	4.208	4.204	4.328
4	Land and Buildings	1.322	1.438	1.532
5	In Lieu	2.288	2.301	2.137
6	Total Property Taxes	$ 18.260	$ 18.248	$ 18.573
7				
8	2024 Forecast Change from 2023 Approved			1.7%
9	2024 Forecast Change from 2023 Projected			1.8%

As shown in the above table, in 2024 property taxes are forecast to increase by 1.7 percent from 2023 Approved and by 1.8 percent from 2023 Projected. In general, the 2024 increase from 2023 Projected is due to construction activities, market value changes, and changes in tax policies of local taxing authorities. The most significant drivers of the forecast changes are as follows:

1. ***Changes in Tax Rates.*** Tax Rates are expected to change for 2024 as follows:
    a) Municipal rates are expected to increase by 0.6 percent;
    b) School rates are expected to decrease by 1.2 percent;
    c) Rural rates are expected to decrease by 0.5 percent;
    d) Tax rates on First Nations are expected to increase by 0.8 percent; and
    e) Other rates are expected to decrease by 1.1 percent.

2. ***Changes in Revenues to Calculate Grants In Lieu of Taxes.*** Revenues reported to municipalities are expected to decrease by 7.1 percent based on actual revenues applicable to the taxation year. Grants in-lieu of taxes are based on a fixed percentage of revenues; the overall actual decrease in revenues reported to municipalities decreases the grants in-lieu of taxes due.

3. ***Changes in Assessed Values.*** Forecast changes in the assessed values of FBC's property are based on expected inflationary increases. These include:

   a) A 5.2 percent increase in assessed values of distribution lines and a 4.7 percent increase in transmission lines;

   b) A 4.1 percent increase in assessed values for generating facilities calculated using legislated cost manuals for valuing generating facilities;

   c) A 2.1 percent decrease in assessed values for substations calculated using legislated cost manuals for valuing substations; and

   d) A 7.1 percent increase for offices.

Any variances from the forecast of property taxes included in rates are recorded in the Flow-through deferral account and will be returned to or recovered from customers in the following year.

9.3 INCOME TAX

FBC is subject to corporate income taxes imposed by the Federal and BC governments. Current income taxes have been calculated using the flow-through (taxes payable) method, consistent with BCUC-approved past practice, at the corporate tax rate of 27 percent for 2023, which is unchanged from 2022. The corporate tax rates used in this Application are based on the *Canada Income Tax Act* and the *BC Income Tax Act* enacted legislation and are updated each year as part of the annual rate setting process.

Income tax for 2024 is forecast to increase by $4.002 million or 65.9 percent compared to 2023 Approved. The largest driver of the increase in 2024 is the lower income tax deductible through capital cost allowance (CCA) by approximately $2.849 million. The lower deductibility is partly due to reduced undepreciated capital cost (UCC) additions in higher rate CCA classes in the 2024 Forecast compared to 2023 Approved, and partly due to the phase-out of Canada's Accelerated Investment Incentive starting from 2024 (i.e., enhanced 50 percent first-year allowance to be phased out in 2024).[49] Income tax is also higher as a result of higher 2024 Forecast earned return and depreciation expense, which is partially offset by lower amortization of deferred charges.

[49] https://www.canada.ca/en/revenue-agency/services/tax/businesses/topics/sole-proprietorships-partnerships/report-business-income-expenses/claiming-capital-cost-allowance/accelerated-investment-incentive.html#AppPhaseOut.

Any tax rate variances and variances in income taxes on items that are flowed through in rates are subject to flow-through treatment.

All other differences in income tax expense are subject to earnings sharing.

9.4 SUMMARY

FBC has forecast its property and income taxes on a basis consistent with prior years, utilizing enacted legislation for income taxes and forecast changes for property tax rates and assessments.

10. EARNINGS SHARING

In the MRP Decision (at page 82), the BCUC approved an earnings sharing mechanism from 2020 to 2024 whereby 50 percent of the achieved ROE above or below the allowed ROE will be shared with customers. Since FBC is unable to determine final earnings sharing until all items required for the ROE calculation are known, including the final rate base, there is a lag in when FBC distributes earnings sharing amounts. This is consistent with the calculations of formula O&M, where the true-up of the formula inputs happens only once actuals are known. Thus, for 2024 rates, it is the 2022 formula O&M and 2022 earnings sharing amounts that are calculated and impact rates in 2024.

For 2024, FBC proposes to distribute a $2.396 million pre-tax credit ($1.749 million after-tax) to customers, comprised of:

- The $1.749 million credit difference between the projected 2022 deferral account after-tax addition of zero embedded in 2023 rates, and the actual 2022 deferral account after-tax credit addition of $1.749 million as provided in FBC's 2022 Annual Report to the BCUC. This amount is also shown in the opening 2024 balance[50] in the financial schedules in the Application.

FBC proposes to distribute $2.396 million to customers in 2024 as a reduction in 2024 revenue requirements through amortization of the projected 2024 opening after-tax balance of $1.749 million in the MRP Earnings Sharing deferral account.

As part of future rate filings, the actual earnings sharing for 2023 will be distributed to or collected from customers in a similar manner as described above, which will account for the actual 2023 ROE variance from approved.

[50] Section 11, Schedule 12.2, Line 14, Column 2.

11. FINANCIAL SCHEDULES

Description	Schedule Reference
Summary Of Rate Change	1
Rate Base	
Utility Rate Base	2
Formula Inflation Factors	3
Capital Expenditures	4
Capital Expenditures To Plant Reconciliation	5
Plant In Service Continuity Schedule	6
Accumulated Depreciation Continuity Schedule	7
Schedule Not Applicable	8
Contributions In Aid Of Construction Continuity Schedule	9
Schedule Not Applicable	10
Unamortized Deferred Charges And Amortization - Rate Base	11
Unamortized Deferred Charges And Amortization - Non-Rate Base	12
Working Capital Allowance	13
Cash Working Capital	14
Schedule Not Applicable	15
Revenue Requirement	
Utility Income And Earned Return	16
Volume And Revenue	17
Revenue At Existing And Revised Rates	18
Cost Of Energy	19
Operating And Maintenance Expense	20
Depreciation And Amortization Expense	21
Property And Sundry Taxes	22
Other Revenue	23
Income Taxes	24
Capital Cost Allowance	25
Return On Capital	26
Embedded Cost Of Long Term Debt	27

FORTISBC INC. FBC Annual Review for 2024 Rates - August 4, 2023 Section 11

Schedule 1

SUMMARY OF RATE CHANGE
FOR THE YEAR ENDING DECEMBER 31, 2024
($millions)

Line No.	Particulars	2024 Forecast		Cross Reference
	(1)	(2)	(3)	(4)
1	**VOLUME/REVENUE RELATED**			
2	Customer Growth and Volume	$ (2.304)		
3	Change in Other Revenue	0.149	(2.155)	
4				
5	**POWER SUPPLY**			
6	Power Purchases	10.119		
7	Wheeling	0.337		
8	Water Fees	0.971	11.427	
9				
10	**O&M CHANGES**			
11	Gross O&M Change	1.655		
12	Capitalized Overhead Change	(0.248)	1.407	
13				
14	**DEPRECIATION EXPENSE**			
15	Depreciation from Net Additions		2.579	
16				
17	**AMORTIZATION EXPENSE**			
18	CIAC from Net Additions	(0.242)		
19	Deferrals	0.487	0.245	
20				
21	**FINANCING AND RETURN ON EQUITY**			
22	Financing Rate Changes	0.346		
23	Financing Ratio Changes	(0.056)		
24	Rate Base Growth	2.566	2.856	
25				
26	**TAX EXPENSE**			
27	Property and Other Taxes	0.313		
28	Other Income Taxes Changes	4.002	4.315	
29				
30	**REVENUE DEFICIENCY (SURPLUS)**		**$ 20.674**	Schedule 16, Line 6, Column 4
31				
32	Revenue at Existing Rates		428.377	Schedule 18, Line 7, Column 3
33	Rate Change		4.83%	

UTILITY RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Schedule 2

Line No.	Particulars	2023 Approved	2024 at Revised Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	Plant in Service, Beginning	$ 2,375,297	$ 2,505,386	$ 130,089	Schedule 6.1, Line 32, Column 3
2	Opening Balance Adjustment	-	-	-	Schedule 6.1, Line 32, Column 4
3	Net Additions	133,903	96,482	(37,421)	Schedule 6.1, Line 32, Column 5+6+7
4	Plant in Service, Ending	2,509,200	2,601,868	92,668	
5					
6	Accumulated Depreciation Beginning	$ (693,759)	$ (741,726)	$ (47,967)	Schedule 7.1, Line 32, Column 5
7	Opening Balance Adjustment	-	-	-	Schedule 7.1, Line 32, Column 6
8	Net Additions	(48,025)	(52,613)	(4,588)	Schedule 7.1, Line 32, Column 7+8+9
9	Accumulated Depreciation Ending	(741,784)	(794,339)	(52,555)	
10					
11	CIAC, Beginning	$ (243,101)	$ (254,724)	$ (11,623)	Schedule 9, Line 3, Column 2
12	Opening Balance Adjustment	-	-	-	
13	Net Additions	(11,628)	(7,539)	4,089	Schedule 9, Line 3, Column 5+6
14	CIAC, Ending	(254,729)	(262,263)	(7,534)	
15					
16	Accumulated Amortization Beginning - CIAC	$ 89,140	$ 94,207	$ 5,067	Schedule 9, Line 7, Column 2
17	Opening Balance Adjustment	-	-	-	
18	Net Additions	5,067	5,309	242	Schedule 9, Line 7, Column 5+6
19	Accumulated Amortization Ending - CIAC	94,207	99,516	5,309	
20					
21	Net Plant in Service, Mid-Year	$ 1,567,236	$ 1,623,963	$ 56,727	
22					
23	Adjustment for timing of Capital additions	$ 22,720	$ 2,750	$ (19,970)	
24	Capital Work in Progress, No AFUDC	34,306	25,574	(8,732)	
25	Unamortized Deferred Charges	40,045	51,287	11,242	Schedule 11, Line 34, Column 8
26	Working Capital	6,099	6,510	411	Schedule 13, Line 9, Column 3
27	Utility Plant Acquisition Adjustment	4,563	4,377	(186)	
28					
29	Mid-Year Utility Rate Base	$ 1,674,969	$ 1,714,461	$ 39,492	

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Schedule 3

FORMULA INFLATION FACTORS
FOR THE YEARS ENDING DECEMBER 31, 2020 to 2024
($000s)

Line No.	Particulars	Reference	2020	2021	2022	2023	2024	Total for 2024 Rate Setting	Cross Ref
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**Formula Cost Drivers**								
2	CPI		2.692%	1.596%	1.281%	4.940%	6.031%		
3	AWE		2.881%	5.745%	6.455%	3.944%	2.609%		
4	Labour Split								
5	Non Labour		38.000%	38.000%	37.000%	40.000%	43.000%		
6	Labour		62.000%	62.000%	63.000%	60.000%	57.000%		
7	CPI/AWE	(Line 2 x Line 5) + (Line 3 x Line 6)	2.809%	4.168%	4.541%	4.342%	4.080%		
8	Productivity Factor	G-166-20	-0.500%	-0.500%	-0.500%	-0.500%	-0.500%		
9	Net Inflation Factor	Line 7 + Line 8	2.309%	3.668%	4.041%	3.842%	3.580%		
10									
11									
12	**Growth in Average Customer Calculation**								
13	Actual/Projected Prior Year Average Customers		139,916	142,321	144,877	147,112	149,677		
14	Average Customers for the Year	Schedule 18, Line 7, Column 6	142,321	144,877	147,112	149,677	152,006		
15	Change in Average Customers	Line 14 - Line 13	2,405	2,556	2,235	2,565	2,329	12,090	
16									
17	Customer Growth Factor Multiplier	G-166-20						75%	
18	Change in Average Customers for Rate Setting Purposes	Line 15 x Line 17						9,068	
19									
20	Average Customers Used to Determine Starting UCOM	Line 13 Year 2020						139,916	
21									
22	Average Customer Forecast - 2024 Rate Setting Purposes	Line 18 + Line 20						148,984	

FORTISBC INC. FBC Annual Review for 2024 Rates - August 4, 2023 Section 11

Schedule 4

CAPITAL EXPENDITURES
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Line No.	Particulars	Total CapEx	Cross Reference
	(1)	(2)	(3)
1	**Forecast Capital Expenditures**		
2	Growth Capital	$ 24,568	
3	Sustainment Capital	51,652	
4	Other Capital	17,213	
5	Total Forecast Capital	$ 93,433	
6			
7	**Flow-Through Capital Expenditures**		
8	EV Charging Stations	$ 500	
9			
10	**Total Regular Capital Expenditures**	$ 93,933	

CAPITAL EXPENDITURES TO PLANT RECONCILIATION
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Line No.	Particulars	2024 Formula		Cross Reference
	(1)	(2)		(3)
1	**CAPEX**			
2	Forecast Capital Expenditures	$	93,433	
3	Flow-Through Capital		500	
4	Total Regular Capital Expenditures	$	93,933	Schedule 4, Line 10, Column 2
5				
6	**Special Projects and CPCN's**			
7				
8	Total Special Projects and CPCN's	$	-	
9				
10	**Total Capital Expenditures**	$	93,933	
11				
12				
13	**RECONCILIATION OF CAPITAL EXPENDITURES TO PLANT**			
14				
15	Regular Capital Expenditures	$	93,933	Line 4
16	Add - Capitalized Overheads		11,148	Schedule 20, Line 23, Column 4
17	Add - AFUDC		241	
18	Gross Capital Expenditures	$	105,322	
19	Change in Work in Progress		-	
20	**Total Regular Additions to Plant**	$	105,322	
21				
22	Special Projects and CPCN's Capital Expenditures	$	-	Line 8
23	Add - AFUDC		1	
24	Gross Capital Expenditures		1	
25	Change in Work in Progress		5,499	
26	**Total Special Projects and CPCN Additions to Plant**	$	5,500	
27				
28	**Grand Total Additions to Plant**	$	110,822	Schedule 6.1, Line 32, Columns 5 + 6

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PLANT IN SERVICE CONTINUITY SCHEDULE Schedule 6
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Line No.	Account	Particulars	12/31/2023	Opening Bal Adjustment	CPCN's	Additions	Retirements	12/31/2024	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1		**Hydraulic Production Plant**							
2	330	Land Rights	$ 962	$ -	$ -	$ -	$ -	$ 962	
3	331	Structures and Improvements	22,199	-	-	166	(12)	22,353	
4	332	Reservoirs, Dams & Waterways	139,590	-	2,731	7,690	(777)	149,234	
5	333	Water Wheels, Turbines and Gen.	106,005	-	-	694	(141)	106,558	
6	334	Accessory Equipment	51,447	-	-	128	(38)	51,537	
7	335	Other Power Plant Equipment	48,576	-	-	5	(1)	48,580	
8	336	Roads, Railroads and Bridges	1,287	-	-	-	-	1,287	
9			$ 370,066	$ -	$ 2,731	$ 8,683	$ (969)	$ 380,511	
10									
11		**Transmission Plant**							
12	350	Land Rights-R/W	$ 10,884	$ -	$ -	$ 118	$ -	$ 11,002	
13	350.1	Land Rights-Clearing	10,109	-	-	118	-	10,227	
14	353	Station Equipment	264,083	-	2,769	3,420	(303)	269,969	
15	355	Poles Towers & Fixtures	134,762	-	-	6,403	(289)	140,876	
16	356	Conductors and Devices	129,994	-	-	6,403	(310)	136,087	
17	359	Roads and Trails	959	-	-	-	-	959	
18			$ 550,791	$ -	$ 2,769	$ 16,462	$ (902)	$ 569,120	

FORTISBC INC.

PLANT IN SERVICE CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Schedule 6.1

Line No.	Account	Particulars	12/31/2023	Opening Bal Adjustment	CPCN's	Additions	Retirements	12/31/2024	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1		**Distribution Plant**							
2	360	Land Rights-R/W	$ 7,995	$ -	$ -	$ 810	$ -	$ 8,805	
3	360.1	Land Rights-Clearing	12,001	-	-	372	-	12,373	
4	362	Station Equipment	324,416	-	-	12,969	(879)	336,506	
5	364	Poles Towers & Fixtures	271,743	-	-	13,565	(577)	284,731	
6	365	Conductors and Devices	456,680	-	-	20,383	(722)	476,341	
7	368	Line Transformers	205,825	-	-	14,062	(1,803)	218,084	
8	369	Services	9,521	-	-	-	-	9,521	
9	370.1	AMI Meters	41,986	-	-	528	-	42,514	
10	371	Installation on Customers' Premises	938	-	-	-	-	938	
11	373	Street Lighting and Signal System	14,304	-	-	168	(42)	14,430	
12	372	EV Stations Kiosks & Charger Connectors	6,265	-	-	-	-	6,265	
13			$ 1,351,674	$ -	$ -	$ 62,857	$ (4,023)	$ 1,410,508	
14									
15		**General Plant**							
16	389	Land	$ 11,268	$ -	$ -	$ -	$ -	$ 11,268	
17	390.1	Structures - Masonry	50,339	-	-	2,765	(317)	52,787	
18	390.2	Operation Building	20,014	-	-	605	(22)	20,597	
19	390.9	Leasehold Improvements	3,727	-	-	-	-	3,727	
20	391	Office Furniture & Equipment	5,376	-	-	214	(5)	5,585	
21	391.1	Computer Hardware	13,899	-	-	3,305	(1,278)	15,926	
22	391.2	Computer Software	44,861	-	-	6,982	(4,254)	47,589	
23	391.2	AMI Software	13,436	-	-	(3)	-	13,433	
24	392.1	Light Duty Vehicles	6,031	-	-	545	(481)	6,095	
25	392.1	Heavy Duty Vehciles	29,840	-	-	1,512	(348)	31,004	
26	394	Tools and Work Equipment	8,637	-	-	719	(658)	8,698	
27	397	Communication Structures & Equipment	14,926	-	-	676	(836)	14,766	
28	397.1	Fibre	5,531	-	-	-	(247)	5,284	
29	397.2	AMI Communications Structure & Equipment	4,970	-	-	-	-	4,970	
30			$ 232,855	$ -	$ -	$ 17,320	$ (8,446)	$ 241,729	
31									
32		**Total Plant in Service**	$ 2,505,386	$ -	$ 5,500	$ 105,322	$ (14,340)	$ 2,601,868	
33									
34		Cross Reference			Schedule 5, Line 26, Column 2	Schedule 5, Line 20, Column 2			

FORTISBC INC.

ACCUMULATED DEPRECIATION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Line No.	Account	Particulars	Gross Plant for Depreciation	Depreciation Rate	12/31/2023	Opening Bal Adjustment	Depreciation Expense	Retirements	Cost of Removal	Adjustments	12/31/2024	Cross Ref
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
1		**Hydraulic Production Plant**										
2	330	Land Rights	$ 962	1.07%	$ (372)	$ -	$ 10	$ -	$ -	$ -	$ (362)	
3	331	Structures and Improvements	22,199	1.68%	6,076	-	373	(12)	-	-	6,437	
4	332	Reservoirs, Dams & Waterways	142,321	1.90%	7,167	-	2,704	(777)	(1,894)	-	7,200	
5	333	Water Wheels, Turbines and Gen.	106,005	1.79%	22,308	-	1,897	(141)	(3)	-	24,061	
6	334	Accessory Equipment	51,447	3.13%	16,560	-	1,610	(38)	(133)	-	17,999	
7	335	Other Power Plant Equipment	48,576	2.12%	21,200	-	1,030	(1)	-	-	22,229	
8	336	Roads, Railroads and Bridges	1,287	1.44%	495	-	19	-	-	-	514	
9			$ 372,797		$ 73,434	$ -	$ 7,643	$ (969)	$ (2,030)	$ -	$ 78,078	
10												
11		**Transmission Plant**										
12	350	Land Rights-R/W	$ 10,884	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
13	350.1	Land Rights-Clearing	10,109	1.27%	2,612	-	128	-	-	-	2,740	
14	353	Station Equipment	266,852	2.33%	107,657	-	6,218	(303)	(162)	-	113,410	
15	355	Poles Towers & Fixtures	134,762	2.52%	41,827	-	3,396	(289)	(479)	-	44,455	
16	356	Conductors and Devices	129,994	2.52%	26,379	-	3,275	(310)	(479)	-	28,865	
17	359	Roads and Trails	959	1.96%	451	-	19	-	-	-	470	
18			$ 553,560		$ 178,926	$ -	$ 13,036	$ (902)	$ (1,120)	$ -	$ 189,940	

FORTISBC INC.

ACCUMULATED DEPRECIATION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Schedule 7.1

Line No.	Account	Particulars	Gross Plant for Depreciation	Depreciation Rate	12/31/2023	Opening Bal Adjustment	Depreciation Expense	Retirements	Cost of Removal	Adjustments	12/31/2024	Cross Ref
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
1		**Distribution Plant**										
2	360	Land Rights-R/W	$ 7,995	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
3	360.1	Land Rights-Clearing	12,001	1.25%	3,080	-	150	-	-	-	3,230	
4	362	Station Equipment	324,416	2.61%	100,441	-	8,467	(879)	(159)	-	107,870	
5	364	Poles Towers & Fixtures	271,743	2.73%	86,032	-	7,419	(577)	(578)	-	92,296	
6	365	Conductors and Devices	456,680	2.38%	138,391	-	10,868	(722)	(933)	-	147,604	
7	368	Line Transformers	205,825	3.13%	49,872	-	6,442	(1,803)	(354)	-	54,157	
8	369	Services	9,521	0.51%	6,856	-	49	-	-	-	6,905	
9	370.1	AMI Meters	41,986	6.25%	15,488	-	2,624	-	-	-	18,112	
10	371	Installation on Customers' Premises	938	0.00%	937	-	-	-	-	-	937	
11	373	Street Lighting and Signal System	14,304	4.95%	6,919	-	708	(42)	-	-	7,585	
12	372	EV Stations Kiosks & Charger Connectors	6,265	10.00%	1,422	-	627	-	-	-	2,049	
13			$ 1,351,674		$ 409,438	$ -	$ 37,354	$ (4,023)	$ (2,024)	$ -	$ 440,745	
14												
15		**General Plant**										
16	389	Land	$ 11,268	0.00%	$ 34	$ -	$ -	$ -	$ -	$ -	$ 34	
17	390.1	Structures - Masonry	50,339	2.53%	14,019	-	1,274	(317)	-	-	14,976	
18	390.2	Operation Building	20,014	1.63%	7,376	-	326	(22)	-	-	7,680	
19	390.9	Leasehold Improvements	3,727	1.63%	2,747	-	61	-	-	-	2,808	
20	391	Office Furniture & Equipment	5,376	4.42%	1,503	-	238	(5)	-	-	1,736	
21	391.1	Computer Hardware	13,899	21.60%	4,422	-	3,002	(1,278)	-	-	6,146	
22	391.2	Computer Software	44,861	8.96%	16,106	-	4,020	(4,254)	-	-	15,872	
23	391.2	AMI Software	13,436	10.00%	8,971	-	1,344	-	-	-	10,315	
24	392.1	Light Duty Vehicles	6,031	3.81%	2,352	-	230	(481)	79	-	2,180	
25	392.1	Heavy Duty Vehciles	29,840	6.50%	9,582	-	1,940	(348)	-	-	11,174	
26	394	Tools and Work Equipment	8,637	4.11%	3,262	-	355	(658)	-	-	2,959	
27	397	Communication Structures & Equipment	14,926	3.44%	4,145	-	513	(836)	(5)	-	3,817	
28	397.1	Fibre	5,531	6.97%	2,687	-	386	(247)	-	-	2,826	
29	397.2	AMI Communications Structure & Equipment	4,970	6.67%	2,722	-	331	-	-	-	3,053	
30			$ 232,855		$ 79,928	$ -	$ 14,020	$ (8,446)	$ 74	$ -	$ 85,576	
31												
32		**Total**	$ 2,510,886		$ 741,726	$ -	$ 72,053	$ (14,340)	$ (5,100)	$ -	$ 794,339	
33												
34		Cross Reference	Schedule 6.1, Line 32, Column 3+4+5									

SCHEDULE NOT APPLICABLE

FORTISBC INC. FBC Annual Review for 2024 Rates - August 4, 2023 Section 11

Schedule 9

CONTRIBUTIONS IN AID OF CONSTRUCTION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Line No.	Particulars	12/31/2023	CPCN / Open Bal Adjt	Adjustment	Additions	Retirements	12/31/2024	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**CIAC**							
2	CIAC	$ 254,724	$ -	$ -	$ 7,539	$ -	$ 262,263	
3	**Total**	$ 254,724	$ -	$ -	$ 7,539	$ -	$ 262,263	
4								
5	**Amortization**							
6	Amortization	$ (94,207)	$ -	$ -	$ (5,309)	$ -	$ (99,516)	
7	**Total**	$ (94,207)	$ -	$ -	$ (5,309)	$ -	$ (99,516)	
8								
9	**Net CIAC**	$ 160,517	$ -	$ -	$ 2,230	$ -	$ 162,747	

SCHEDULE NOT APPLICABLE

FORTISBC INC. FBC Annual Review for 2024 Rates - August 4, 2023 Section 11

Schedule 11

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Line No.	Particulars	12/31/2023	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	12/31/2024	Mid-Year Average	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**1. Forecasting Variance Accounts**								
2	BCUC Levies Variance Account	$ 36	$ -	$ -	$ -	$ (36)	$ -	$ 18	
3									
4	**2. Rate Smoothing Accounts**								
5									
6	**3. Benefits Matching Accounts**								
7	Preliminary and Investigative Charges '	$ 2,923	$ -	$ 328	$ -	$ -	$ 3,251	$ 3,087	Note 1
8	Demand Side Management	41,573	-	15,436	(4,168)	(6,287)	46,554	44,063	
9	Deferred Debt Issue Costs	4,391	-	-	(110)	(196)	4,084	4,237	
10	2025 Multi-year Rate Plan Application	256	-	1,200	(324)	-	1,132	694	
11	2023 - 2027 DSM Expenditure Schedule	62	-	-	-	(16)	47	55	
12	Mandatory Reliability Standards 2024 Audit	-	-	375	(101)	(91)	183	91	
13	Joint Pole Use Audit 2023	356	-	-	-	(89)	267	312	
14	2021 Generic Cost of Capital Proceeding	770	-	-	-	-	770	770	
15	Annual Reviews for 2020-2024 Rates	49	-	90	(25)	(49)	66	58	
16	2021 Long Term Electric Resource Plan	329	-	-	-	(174)	155	242	
17	BCUC Initiated Inquiry Costs	(57)	-	-	-	57	-	(28)	
18	EV Fleet & Workplace Charging Funding Account	-	169	576	(155)	(17)	572	371	
19	Mandatory Reliability Standards 2021 Audit	78	-	-	-	(78)	-	39	
20		$ 50,730	$ 169	$ 18,005	$ (4,883)	$ (6,940)	$ 57,080	$ 53,991	
21									
22	**4. Retroactive Expense Accounts**								
23									
24	**5.Other Accounts**								
25	Pension and OPEB Liability	$ (5,046)	$ -	$ 5,220	$ -	$ -	$ 174	$ (2,436)	
26	COVID-19 Customer Recovery Fund	139	-	-	-	(70)	68	104	
27	Climate Change Operational Adaptation (CCOA)	164	-	192	(52)	(41)	263	214	
28	BC Cost of Living Credit	(370)	-	-	-	370	-	(185)	
29	Princeton Office Disposition	-	(406)	-	-	406	-	(203)	
30	PST Rebate on Select Machinery and Equipment	(431)	-	-	-	431	-	(216)	
31	Indigenous Relations Agreement (Huth Substation)	-	-	-	-	-	-	-	
32		$ (5,545)	$ (406)	$ 5,412	$ (52)	$ 1,096	$ 506	$ (2,722)	
33									
34	**Total Rate Base Deferral Accounts**	$ 45,221	$ (237)	$ 23,417	$ (4,935)	$ (5,880)	$ 57,586	$ 51,287	
35									

36 Note 1: Gross Additions for Preliminary and Investigative Charges are after transfers to Construction Work in Progress. Additions of $1.60 million - transfer of $1.272 million = $0.328 million.

FORTISBC INC. FBC Annual Review for 2024 Rates - August 4, 2023 Section 11

Schedule 12

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - NON-RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Line No.	Particulars	12/31/2023	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	12/31/2024	Mid-Year Average	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**Deferral Accounts Financed at Short Term Interest Rate**								
2									
3	**1. Forecasting Variance Accounts**								
4	Pension & Other Post Retirement Benefits (OPEB) Variance	$ (169)	$ -	$ -	$ -	$ (246)	$ (415)	$ (292)	
5									
6	**2. Rate Smoothing Accounts**								
7									
8	**3. Benefits Matching Accounts**								
9	Tariff Applications	86	-	75	(20)	(86)	54	70	
10									
11	**4. Retroactive Expense Accounts**								
12									
13	**5.Other Accounts**								
14									
15	**Total NRB Deferral Accounts at Short Term Interest**	$ (83)	$ -	$ 75	$ (20)	$ (332)	$ (361)	$ (222)	
16									
17	Financing Costs at STI	$ 27	$ -	$ (7)	$ -	$ (27)	$ (7)	$ 10	

FORTISBC INC.

Schedule 12.1

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - NON-RATE BASE cont'd
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Line No.	Particulars	12/31/2023	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	12/31/2024	Mid-Year Average	Cross Ref
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**Deferral Accounts Financed at Weighted Average Cost of Debt**								
2									
3	**1. Forecasting Variance Accounts**								
4									
5	**2. Rate Smoothing Accounts**								
6									
7	**3. Benefits Matching Accounts**								
8	CPCN Projects Preliminary Engineering [1]	$ 2,666	$ -	$ (255)	$ -	$ -	$ 2,411	$ 2,538	Note 1
9	2017 Rate Design Application	118	-	-	-	(118)	-	59	
10	2020 - 2024 Multi-Year Rate Plan Application	145	-	-	-	(145)	-	72	
11	Rate Design and Rates for Electric Vehicle Direct Current Fast Charging Service Application	68	-	-	-	(59)	9	38	
12		$ 2,996	$ -	$ (255)	$ -	$ (322)	$ 2,420	$ 2,707	
13									
14	**4. Retroactive Expense Accounts**								
15									
16	**5.Other Accounts**								
17									
18	**Total NRB Deferral Accounts at Weighted Average Cost of Debt**	$ 2,996	$ -	$ (255)	$ -	$ (322)	$ 2,420	$ 2,707	
19									
20	Financing Costs at WACD	$ 76	$ -	$ 95	$ -	$ (76)	$ 95	$ 86	

21 Note 1: Gross additions for CPCN Projects Preliminary Engineering after transfers to Construction Work in Progress.

FORTISBC INC.

Schedule 12.2

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - NON-RATE BASE cont'd
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Line No.	Particulars	12/31/2023	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	12/31/2024	Mid-Year Average	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**Deferral Accounts Financed at Weighted Average Cost of Capital**								
2									
3	**1. Forecasting Variance Accounts**								
4	2020 - 2024 Flow-Through Deferral Account	$ (6,520)	$ -	$ -	$ -	$ 6,520	$ -	$ (3,260)	
5									
6	**2. Rate Smoothing Accounts**								
7									
8	**3. Benefits Matching Accounts**								
9	EV Fleet & Workplace Charging Funding Account	$ 169	$ (169)	$ -	$ -	$ -	$ -	$ -	
10									
11	**4. Retroactive Expense Accounts**								
12									
13	**5.Other Accounts**								
14	MRP Earnings Sharing Account	$ (1,749)	$ -	$ -	$ -	$ 1,749	$ -	$ (875)	
15	Princeton Office Disposition	(406)	406	-	-	-	-	-	
16									
17	**Total NRB Deferral Accounts at Weighted Average Cost of Capital**	$ (8,506)	$ 237	$ -	$ -	$ 8,269	$ -	$ (4,135)	
18									
19	Financing Costs at AFUDC	$ (1,228)	$ -	$ (272)	$ -	$ 1,228	(272)	(750)	
20									
21	**Non Rate Base Deferral Accounts Non-Interest Bearing**	$ 50	$ -	$ -	$ -	$ -	$ 50	$ 50	
22									
23									
24	**Total Non Rate Base Deferral Accounts (including financing)**	$ (6,668)	$ 237	$ (364)	$ (20)	$ 8,740	$ 1,924	$ (2,254)	

FORTISBC INC.

FBC Annual Review for 2024 Rates - August 4, 2023

Section 11

Schedule 13

WORKING CAPITAL ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Line No.	Particulars	2023 Approved	2024 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Cash Working Capital**				
2	Cash Working Capital	$ 6,849	$ 7,367	$ 518	Schedule 14, Line 32, Column 5
3					
4	Add/Less: Funds Unavailable/(Funds Available)				
5	Customers Loans	353	306	(47)	
6	Employee Loans	570	509	(61)	
7	Inventories - Materials and Supplies	649	783	134	
8	Employee Withholdings	(2,322)	(2,455)	(133)	
9	Total	$ 6,099	$ 6,510	$ 411	

FORTISBC INC.

FBC Annual Review for 2024 Rates - August 4, 2023

Section 11

Schedule 14

CASH WORKING CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Line No.	Particulars	2024 at Revised Rates	Lag (Lead) Days	Extended	Weighted Average Lag (Lead) Days	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)
1	**REVENUE**					
2	**Sales Revenue**					
3	Residential Tariff Revenue	$ 215,950	56.0	$ 12,093,200		
4	Commercial Tariff Revenue	116,156	45.1	5,238,636		
5	Wholesale Tariff Revenue	58,256	37.5	2,184,600		
6	Industrial Tariff Revenue	52,203	38.0	1,983,714		
7	Lighting Tariff Revenue	2,328	34.6	80,549		
8	Irrigation Tariff Revenue	4,158	47.0	195,426		
9						
10	**Other Revenue**					
11	Apparatus and Facilities Rental	$ 6,199	90.0	$ 557,894		
12	Contract Revenue	2,260	62.2	140,563		
13	Transmission Access Revenue	1,723	65.2	112,340		
14	Late Payment Charges	962	54.0	51,922		
15	Connection Charges	561	30.5	17,104		
16	Other Utility Income	388	63.4	24,606		
17	Total	$ 461,143		$ 22,680,554		49.2
18						
19	**EXPENSES**					
20	Power Purchases	$ 173,694	(51.5)	$ (8,945,261)		
21	Wheeling	7,324	(46.9)	(343,514)		
22	Water Fees	12,513	(1.4)	(17,518)		
23	Operating and Maintenance	63,174	(28.6)	(1,806,768)		
24	Property Taxes	18,573	(4.9)	(91,008)		
25	GST	703	(45.4)	(31,916)		
26	Income Tax	10,075	(15.2)	(153,140)		
27	Total	$ 286,057		$ (11,389,125)		(39.8)
28						
29	Net Lag (Lead) Days					9.4
30	Total Expenses				$	286,057
31						
32	Cash Working Capital				$	7,367

Schedule 15

SCHEDULE NOT APPLICABLE

FORTISBC INC. FBC Annual Review for 2024 Rates - August 4, 2023 Section 11

Schedule 16

UTILITY INCOME AND EARNED RETURN
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Line No.	Particulars	2023 Approved	2024 Forecast at 2023 Approved Rates	Revised Revenue	2024 Forecast at Revised Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**ENERGY VOLUMES**						
2	Sales Volume (GWh)	3,475	3,474	-	3,474	(1)	Schedule 17, Line 8, Column 3
3							
4	**REVENUE**						
5	Sales	$ 426,073	$ 428,377	$ -	$ 428,377	$ 2,304	Schedule 17, Line 17, Column 3
6	Deficiency (Surplus)	-	-	20,674	20,674	20,674	
7	Total	426,073	428,377	20,674	449,051	22,978	Schedule 18, Line 7, Column 5
8							
9	**EXPENSES**						
10	Cost of Energy	$ 182,105	$ 193,532	$ -	$ 193,532	$ 11,427	Schedule 19, Line 29, Column 3
11	O&M Expense (net)	61,767	63,174	-	63,174	1,407	Schedule 20, Line 24, Column 4
12	Depreciation & Amortization	61,246	64,070	-	64,070	2,824	Schedule 21, Line 11, Column 3
13	Property Taxes	18,260	18,573	-	18,573	313	Schedule 22, Line 6, Column 3
14	Other Revenue	(12,241)	(12,092)	-	(12,092)	149	Schedule 23, Line 8, Column 3
15	Utility Income Before Income Taxes	114,936	101,120	20,674	121,794	6,859	
16							
17	Income Taxes	6,073	4,498	5,577	10,075	4,002	Schedule 24, Line 13, Column 3
18							
19	**EARNED RETURN**	$ 108,863	$ 96,622	$ 15,097	$ 111,719	$ 2,857	Schedule 26, Line 5, Column 7
20							
21	**UTILITY RATE BASE**	$ 1,674,969	$ 1,713,933		$ 1,714,461	$ 39,492	Schedule 2, Line 29, Column 3
22	**RATE OF RETURN ON UTILITY RATE BASE**	6.50%	5.64%		6.52%	0.02%	Schedule 26, Line 5, Column 6

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Schedule 17

VOLUME AND REVENUE
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Line No.	Particulars	2023 Approved	2024 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**ENERGY VOLUME SOLD (GWh)**				
2	Residential	1,300	1,299	(1)	
3	Commercial	973	974	1	
4	Wholesale	579	590	11	
5	Industrial	575	564	(11)	
6	Lighting	9	9	-	
7	Irrigation	39	38	(1)	
8	Total	3,475	3,474	(1)	
9					
10	**REVENUE AT EXISTING RATES**				
11	Residential	$ 205,734	$ 206,007	$ 273	
12	Commercial	110,490	110,808	318	
13	Wholesale	54,100	55,574	1,474	
14	Industrial	49,759	49,800	41	
15	Lighting	2,295	2,221	(74)	
16	Irrigation	3,695	3,967	272	
17	Total	$ 426,073	$ 428,377	$ 2,304	

FORTISBC INC. FBC Annual Review for 2024 Rates - August 4, 2023 Section 11

REVENUE AT EXISTING AND REVISED RATES
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Schedule 18

Line No.	Particulars	2023 Approved Revenue	2024 Forecast: Revenue at 2023 Approved Rates	2024 Forecast: Effective Increase	2024 Forecast: Revenue at Revised Rates	Average Number of Customers	GWh	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	Residential	$ 205,734	$ 206,007	$ 9,943	$ 215,950	132,389	1,299	
2	Commercial	110,490	110,808	5,348	116,156	17,125	974	
3	Wholesale	54,100	55,574	2,682	58,256	6	590	
4	Industrial	49,759	49,800	2,403	52,203	42	564	
5	Lighting	2,295	2,221	107	2,328	1,341	9	
6	Irrigation	3,695	3,967	191	4,158	1,103	38	
7	Total	$ 426,073	$ 428,377	$ 20,674	$ 449,051	152,006	3,474	
8								
9	**Effective Increase**			4.83%				

FORTISBC INC. FBC Annual Review for 2024 Rates - August 4, 2023 Section 11

COST OF ENERGY Schedule 19
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Line No.	Particulars	2023 Approved	2024 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**POWER PURCHASES**				
2	Gross Load (GWh)	3,775	3,773	(2)	
3					
4	**Power Purchase Expense**				
5	Brilliant	$ 44,050	$ 44,433	$ 383	
6	BC Hydro PPA	71,302	71,680	378	
7	Waneta Expansion	41,834	40,365	(1,469)	
8	Market and Contracted Producers	6,326	16,972	10,646	
9	Independent Power Producers	62	245	183	
10	CPA Balancing Pool	-	0	0	
11	Total	$ 163,575	$ 173,694	$ 10,119	
12					
13	**WHEELING**				
14	**Wheeling Nomination (MW months)**				
15	Okanagan Point of Interconnection	2,670	2,595	(75)	
16	Creston	420	450	30	
17					
18	**Wheeling Expense**				
19	Okanagan Point of Interconnect	$ 5,555	$ 5,813	$ 258	
20	Creston	570	658	88	
21	Other	863	854	(9)	
22	Total	$ 6,987	$ 7,324	$ 337	
23					
24	**WATER FEES**				
25	Plant Entitlement Use in previous year (GWh)	1,571	1,561	(10)	
26					
27	Water Fees	$ 11,543	$ 12,513	$ 971	
28					
29	Total	$ 182,105	$ 193,532	$ 11,427	

OPERATING AND MAINTENANCE EXPENSE
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Schedule 20

Line No.	Particulars	Inflation Indexed O&M	Forecast O&M	Total O&M	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Inflation Indexed O&M**				
2	2023 Base Unit Cost O&M	$ 472			
3	2024 Net Inflation Factor	3.580%			Schedule 3, Line 9, Column 7
4	2024 Base Unit Cost O&M	$ 489			Line 2 x (1 + Line 3)
5					
6	2024 Average Customer Forecast - Rate Setting Purpose	148,984			Schedule 3, Line 22, Column 8
7					
8	2024 Inflation Indexed O&M before prior year True-up	$ 72,853			Line 4 x Line 6 / 1,000
9					
10	2022 Average Customer True-up	(30)			
11					
12	2024 Inflation Indexed O&M	$ 72,823		$ 72,823	Sum of Lines 8 and 10
13					
14	**O&M Tracked Outside of Formula**				
15	Pension & OPEB (O&M Portion)		$ (2,532)		
16	Insurance Premiums		2,678		
17	BCUC Levies		458		
18	MRS		585		
19	EV Charging Stations		310		
20	Sub-total		$ 1,499	1,499	Sum of Lines 15 through 19
21					
22	**Total Gross O&M**			$ 74,322	Line 12 + Line 20
23	Capitalized Overhead			(11,148)	-15 % x Line 22
24	**Net O&M Expense**			$ 63,174	Sum of Lines 22 and 23

DEPRECIATION AND AMORTIZATION EXPENSE
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Line No.	Particulars	2023 Approved	2024 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Depreciation**				
2	Depreciation Expense	$ 69,474	$ 72,053	$ 2,579	Schedule 7.1, Line 32, Column 7
3					
4	**Amortization**				
5	Rate Base Deferrals	$ 6,716	$ 5,880	$ (836)	Schedule 11, Line 34, Column 6
6	Non-Rate Base Deferrals	(10,063)	(8,740)	1,323	Schedule 12.2, Line 24, Column 6
7	Utility Plant Acquisition Adjustment	186	186	-	
8	CIAC	(5,067)	(5,309)	(242)	Schedule 9, Line 7, Column 5
9		(8,228)	(7,983)	245	
10					
11	Total	$ 61,246	$ 64,070	$ 2,824	

FORTISBC INC.

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Section 11

Schedule 22

PROPERTY AND SUNDRY TAXES
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Line No.	Particulars	2023 Approved	2024 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	Generating Plant	$ 3,253	$ 3,259	$ 6	
2	Transmission and Distribution	7,189	7,317	128	
3	Substation Equipment	4,208	4,328	120	
4	Land and Buildings	1,322	1,532	210	
5	1% In-Lieu of Municipal Taxes	2,288	2,137	(151)	
6	Total	$ 18,260	$ 18,573	$ 313	

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OTHER REVENUE Schedule 23
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Line No.	Particulars	2023 Approved	2024 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	Apparatus and Facilities Rental	$ 6,108	$ 6,199	$ 91	
2	Contract Revenue	2,367	2,260	(107)	
3	Transmission Access Revenue	1,834	1,723	(111)	
4	Interest Income	30	37	7	
5	Late Payment Charges	994	962	(32)	
6	Connection Charges	553	561	8	
7	Other Recoveries	355	351	(4)	
8	Total	$ 12,241	$ 12,092	$ (149)	

FORTISBC INC.

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Section 11

Schedule 24

INCOME TAXES
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Line No.	Particulars	2023 Approved	2024 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**EARNED RETURN**	$ 108,863	$ 111,719	$ 2,856	Schedule 16, Line 19, Column 5
2	Deduct: Interest on Debt	(47,559)	(48,970)	(1,411)	Schedule 26, Line 1+2, Column 7
3	Adjustments to Taxable Income	(44,884)	(35,508)	9,376	Line 32
4	Accounting Income After Tax	$ 16,420	$ 27,241	$ 10,821	
5					
6	1 - Current Income Tax Rate	73.00%	73.00%	0.00%	
7	Taxable Income	$ 22,493	$ 37,316	$ 14,823	
8					
9	Current Income Tax Rate	27.00%	27.00%	0.00%	
10	Income Tax - Current	$ 6,073	$ 10,075	$ 4,002	
11					
12	Previous Year Adjustment	-	-	-	
13	**Total Income Tax**	$ 6,073	$ 10,075	$ 4,002	
14					
15					
16	**ADJUSTMENTS TO TAXABLE INCOME**				
17	Addbacks:				
18	Depreciation	$ 69,474	$ 72,053	$ 2,579	Schedule 21, Line 2, Column 3
19	Amortization of Deferred Charges	(3,347)	(2,860)	487	Schedule 21, Line 5+6, Column 3
20	Amortization of Utility Plant Acquisition Adjustment	186	186	-	Schedule 21, Line 7, Column 3
21	Pension Expense	(528)	(1,501)	(973)	
22	OPEB Expense	1,119	844	(275)	
23					
24	Deductions:				
25	Capital Cost Allowance	(89,602)	(81,899)	7,703	Schedule 25, Line 18, Column 6
26	CIAC Amortization	(5,067)	(5,309)	(242)	Schedule 21, Line 8, Column 3
27	Pension Contributions	(4,203)	(3,811)	392	
28	OPEB Contributions	(705)	(752)	(47)	
29	Overheads Capitalized Expensed for Tax Purposes	(10,900)	(11,148)	(248)	Schedule 20, Line 23, Column 4
30	Removal Costs	(1,200)	(1,200)	-	
31	All Other	(111)	(111)	-	
32	Total	$ (44,884)	$ (35,508)	$ 9,376	

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Schedule 25

CAPITAL COST ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Line No.	Class	CCA Rate	12/31/2023 UCC Balance	2024 Additions & Opening Adjt	Adjustment	2024 CCA	Forecast 12/31/2024 UCC Balance
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	1(a)	4%	$ 147,922	$ -	$ -	$ (5,917)	$ 142,005
2	1(b)	6%	33,070	3,010	-	(2,165)	33,915
3	2	6%	10,719	-	-	(643)	10,076
4	3	5%	616	-	-	(31)	585
5	6	10%	2	-	-	-	2
6	8	20%	3,538	833	-	(874)	3,497
7	10	30%	4,308	1,838	-	(1,844)	4,302
8	13	0%	11	-	-	-	11
9	14.1 (pre 2017)	7%	6,441	-	-	(451)	5,990
10	14.1 (post 2016)	5%	4,926	1,266	-	(310)	5,882
11	17	8%	161,210	8,533	-	(13,579)	156,164
12	42	12%	8,987	604	-	(1,151)	8,440
13	43.1	30%	477	-	-	(143)	334
14	46	30%	1,896	-	-	(569)	1,327
15	47	8%	530,216	64,669	-	(47,591)	547,294
16	50	55%	2,869	9,188	-	(6,631)	5,426
17							
18	Total		$ 917,208	$ 89,941	$ -	$ (81,899)	$ 925,250

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Schedule 26

RETURN ON CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Line No.	Particulars	2023 Approved Earned Return	Amount	Ratio	2024 Average Embedded Cost	Cost Component	Earned Return	Earned Return Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	Long Term Debt	$ 43,709	$ 935,137	54.54%	4.72%	2.57%	$ 44,097	$ 388	Schedule 27, Line 11, Column 6
2	Short Term Debt	3,850	93,540	5.46%	5.21%	0.28%	4,873	1,023	
3	Common Equity	61,304	685,784	40.00%	9.15%	3.66%	62,749	1,445	
4									
5	Total	$ 108,863	$ 1,714,461	100.00%		6.52%	$ 111,719	$ 2,856	
6									
7	Cross Reference		Schedule 2, Line 29, Column 3						

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Section 11

Schedule 27

EMBEDDED COST OF LONG TERM DEBT
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Line No.	Particulars	Issue Date	Maturity Date	Average Principal Outstanding	Interest Rate	Interest Expense	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	2005 Debt Issue - Series 1 - 05	November 9, 2005	November 9, 2035	$ 100,000	5.600%	$ 5,600	
2	2007 Debt Issue - Series 1 - 07	July 4, 2007	July 4, 2047	105,000	5.900%	6,195	
3	2009 Debt Issue - MTN - 09	June 2, 2009	June 2, 2039	105,000	6.100%	6,405	
4	2010 Debt Issue - MTN - 10	November 24, 2010	November 24, 2050	100,000	5.000%	5,000	
5	2014 Debt Issue - MTN - 14	October 28, 2014	October 28, 2044	200,000	4.000%	8,000	
6	2017 Debt Issue - MTN - 17	December 4, 2017	December 6, 2049	75,000	3.620%	2,715	
7	2020 Debt Issue - MTN - 20	May 11, 2020	May 11, 2050	75,000	3.120%	2,340	
8	2022 Debt Issue - MTN - 22	March 14, 2022	March 14, 2052	100,000	4.160%	4,160	
9	2024 Debt Issue - MTN - 24	April 1, 2024	April 1, 2054	75,137	4.900%	3,682	
10							
11	Total			$ 935,137		$ 44,097	
12							
13	Average Embedded Cost				4.72%		

12. ACCOUNTING MATTERS

12.1 INTRODUCTION AND OVERVIEW

In this section, FBC discusses "Exogenous Factors" under its MRP. FBC also discusses emerging accounting guidance, and the status of its non-rate base deferral accounts. With respect to its non-rate base deferral accounts, FBC provides information on the Flow-through deferral account.

12.2 EXOGENOUS (Z) FACTORS

FBC is permitted to adjust the cost of service for "Exogenous Factors" under the MRP. The BCUC established the following criteria for evaluating whether the impact of an event qualifies for exogenous factor treatment:

1. The costs/savings must be attributable entirely to events outside the control of a prudently operated utility;
2. The costs/savings must be directly related to the exogenous event and clearly outside the base upon which the rates were originally derived;
3. The impact of the event was unforeseen;
4. The costs must be prudently incurred; and
5. The costs/savings related to each exogenous event must exceed the BCUC-defined materiality threshold.

The materiality threshold (item 5) for FBC has been established at $0.150 million, as approved in the MRP Decision.

In 2022 and thus far in 2023, FBC has not identified any items that merit exogenous factor treatment.

12.3 ACCOUNTING MATTERS

In the following section, FBC provides information on emerging accounting guidance.

12.3.1 Emerging Accounting Guidance

In the 2014-2019 PBR Plan Decision and Order G-139-14, the BCUC directed FBC to "communicate any accounting policy changes and updates to the Commission and other stakeholders as part of the Annual Review process during the PBR period." While this directive was not included as part of the MRP Decision, FBC will continue to provide accounting policy changes and updates as part of the Annual Review materials.

There are no new accounting policy changes that FBC is proposing, or that are required to be implemented under US GAAP, that result in a change in accounting for 2024.

12.4 NON-RATE BASE DEFERRAL ACCOUNTS

FBC maintains both rate base and non-rate base deferral accounts. Rate base deferral accounts are included in rate base and earn a rate base return. In contrast, non-rate base deferral accounts are outside of rate base and may have varying rates of return, depending on the nature of the account and the return approved by the BCUC.

In the following section, FBC provides information on its Flow-through deferral account. Information on FBC's non-rate base earnings sharing deferral account is included in Section 10.

12.4.1 New Deferral Accounts

FBC is not seeking approval of any new non-rate base deferral accounts in this Application.

12.4.2 Existing Deferral Accounts

In the section below, FBC discusses the Flow-through deferral account.

12.4.2.1 Flow-Through Deferral Account (2020-2024)

As approved by Order G-166-20, the Flow-through deferral account is used to capture the annual variances between the approved and actual amounts for all costs and revenues which are forecast annually, are not subject to earnings sharing, and which do not have a previously approved deferral account. The specific items included in the Flow-through deferral account were set out in Table C4-1 of the MRP Application, reproduced below.

Table 12-1: Variances Captured in the Flow-through Deferral Account

	FEI	FBC
Delivery Revenues (FEI):		
Residential and commercial use rate variances	RSAM	N/A
Customer variances	Flow-through deferral	N/A
Industrial and all other revenue variances	Flow-through deferral	N/A
Revenues and Power Supply (FBC):		
Revenue variances	N/A	Flow-through deferral
Power Supply variances net of PSI	N/A	Flow-through deferral
Gross O&M:		
Index-based O&M variances	Subject to earnings sharing	Subject to earnings sharing
BCUC fees variances	BCUC variances deferral	BCUC variances deferral
Pension & OPEB variances	Pension/OPEB variances deferral	Pension/OPEB variances deferral
All other O&M variances [1,3]	Flow-through deferral	Flow-through deferral
Capitalized Overhead:		
Capitalized overhead variances	No variance	No variance
Depreciation and Amortization:		
Depreciation rate variances	No variance	No variance
Depreciation on Clean Growth Projects [2,3]	Flow-through deferral	Flow-through deferral
Other depreciation variances	Subject to earnings sharing	Subject to earnings sharing
Amortization of deferrals	No variance	No variance
Property Tax:		
Property tax variances	Flow-through deferral	Flow-through deferral
Other Revenues :		
SCP Mitigation revenues variances	SCP Revenues deferral	N/A
CNG/LNG Recoveries variances	CNG/LNG Recoveries deferral	N/A
Revenues from Clean Growth Projects [2,3]	Flow-through deferral	Flow-through deferral
All other other revenue/income variances	Subject to earnings sharing	Subject to earnings sharing
Interest Expense/Cost of Debt:		
Interest on RSAM/CCRA/MCRA/Gas storage	Interest on RSAM/CCRA/MCRA/Gas Storage	N/A
Interest rate variances	Flow-through deferral	Flow-through deferral
Interest on Clean Growth Projects [2,3]	Flow-through deferral	Flow-through deferral
Other interest variances	Subject to earnings sharing	Subject to earnings sharing
Income Tax:		
Income tax rate variances	Flow-through deferral	Flow-through deferral
Income tax on Clean Growth Projects [2,3]	Flow-through deferral	Flow-through deferral
Other income tax variances	Subject to earnings sharing	Subject to earnings sharing

1: Including items forecast outside of the formula such as insurance premiums, NGT stations, biomethane, variable LNG production, integrity digs and EV charging stations.
2: Cost of service for NGT fueling stations and tankers, variable LNG production, and EV stations will be captured in the Flow-through deferral account.
3: Biomethane other revenues will continue to capture the actual cost of service of the biomethane capital assets and transfer it to the BVA

In accordance with the method set out in the table above, the calculation of the 2023 Projected Flow-through amount of $2.898 million debit is shown in Table 12-2 below. To calculate the overall combined amount to be distributed to customers, FBC has also included the following adjustment:

- The $9.418 million credit difference between the projected ending 2022 deferral account credit balance of $9.693 million[51] embedded in 2023 rates, and the actual ending 2022 deferral credit balance of $19.111 million. A more detailed breakout of the 2022 variance is provided in Table 12-3 below. FBC notes that the financing return on this account is included in the aggregate financing of deferral accounts at Section 11, Schedule 12.2, Line 19.

Table 12-2: 2023 Projected Flow-through Deferral Account Additions ($ millions)

Line No.	Particulars	2023 Approved	2023 Projected	After-Tax Flow-Through Variance
	(1)	(2)	(3)	(4)
1	**Total Revenue**	$ (426.073)	$ (431.720)	$ (5.647)
2				
3	**Total Power Purchase Expense**	163.575	170.873	7.298
4				
5	**Total Wheeling**	6.987	7.294	0.307
6				
7	**Total Water Fees**	11.543	12.433	0.890
8				
9	**Net O&M Expense**			
10	Pension & OPEB	(1.297)	(1.297)	-
11	Insurance	2.457	2.507	0.050
12	BCUC Fees	0.385	0.385	-
13	MRS	0.585	0.585	-
14	EV Charging Stations	0.219	0.181	(0.038)
15	Capitalized Overhead	(10.900)	(10.900)	-
16				
17	**Depreciation and Amortization**			
18	Amortization of Deferrals	(3.347)	(3.347)	-
19	Depreciation variance on Clean Growth Projects/CPCNs/Exogenous Capital	-	-	-
20	CIAC Amortization variance on Clean Growth Projects/CPCNs/Exogenous Capital	-	-	-
21				
22	**Total Property Taxes**	18.260	18.248	(0.012)
23				
24	**Other Revenues**			
25	EV Carbon Credits	-	(0.544)	(0.544)
26				
27	**Interest Expense**			
28	Long-term debt interest expense variance	43.709	41.856	(1.853)
29	Interest variance on Clean Growth Projects/CPCNs/Exogenous Capital	-	-	-
30	Short-term debt rate variance	-	1.353	1.353
31	Short-term debt volume variance from long-term debt issue variance	-	2.166	2.166
32	Short-term debt timing variance from long-term debt issue timing	-	-	-
33				
34	**Income Tax Expense**			
35	Income tax variance on Clean Growth Projects/CPCNs/Exogenous Capital	-	-	-
36	Income tax/CCA rate changes	-	-	-
37	Income tax on taxable flowthrough variances above (excl. Clean Growth Projects/CPCNs/Exogenous Capital)	-	(1.072)	(1.072)
38				
39	**2023 After-Tax Flow-Through Addition to Deferral Account (excluding Financing)**			**2.898**
40				
41	2022 Ending Deferral Account Balance True-up			(9.418)
42				
43	**2024 After-Tax Amortization**			**(6.520)**

[51] FBC Annual Review for 2023 Rates, April 24, 2023 finalized financial schedules supporting 2023 Interim Rates, Schedule 12.2, Line 4, Column 2.

12.4.2.1.1 2023 PROJECTED FLOW-THROUGH VARIANCES

FBC provides the following explanations for the 2023 Projected flow-through variances shown in Table 12-2 above:

- The variance in revenue is due to increased sales from residential, commercial, and wholesale customers;
- The variance in power purchase expense is primarily due to increased Market and Contracted Purchases required to address supply gaps and reduce exposure to potentially extreme market prices. FBC purchased forward market blocks to cover projected capacity shortfalls in June 2023 and reduce exposure to Tranche 2 energy under the PPA with BC Hydro. FBC also purchased wholesale market power from the spot market, at rates economic to the PPA during the first six months of the year, to reduce required purchases above the BC Hydro PPA Nomination. Also included in the Projected 2023 expense are planned wholesale market purchases in November and December 2023, consistent with the strategy presented in the 2023/24 Annual Electric Contracting Plan (AECP);
- Variances in wheeling and water fees are discussed in Section 4;
- Flow-through O&M amounts are discussed in Section 6;
- Amortization expense is equal to the approved value;
- Variances in property taxes are described in Section 9;
- Variances in other revenues are described in Section 5;
- The projected interest expense variances are derived from FBC forecasting issuing long-term debt in 2023 in the Annual Review for 2023 Rates, whereas FBC is no longer projecting a debt issuance, and FBC projecting a higher short-term interest rate than the approved short-term interest rate, both as described in Section 8; and
- The income tax variance is derived as 27 percent of the aforementioned variances.

An adjustment to include the difference between the projected and final actual amounts for 2023 subject to flow-through will be recorded in the deferral account in 2023 and amortized in 2025 rates.

12.4.2.1.2 2022 FLOW-THROUGH DEFERRAL ACCOUNT TRUE-UP

Table 12-3 below provides a breakdown of the 2022 true-up amount of $9.418 million credit.

Table 12-3: 2022 Actual vs. Projected Flow-through Deferral Account Additions ($ millions)

Line No.	Particulars	2022 Projected	2022 Actual	After-Tax Flow-Through Variance
	(1)	(2)	(3)	(4)
1	**Total Revenue**	$ (414.385)	$ (425.782)	$ (11.397)
2				
3	**Total Power Purchase Expense**	153.164	153.457	0.293
4				
5	**Total Wheeling**	6.330	6.898	0.568
6				
7	**Total Water Fees**	11.916	11.838	(0.078)
8				
9	**Net O&M Expense**			
10	Pension & OPEB	(1.716)	(1.716)	-
11	Insurance	2.291	2.286	(0.005)
12	BCUC Fees	0.373	0.373	-
13	MRS	0.500	0.468	(0.032)
14	EV Charging Stations	0.187	0.213	0.026
15	COVID-19 Pandemic	(1.030)	(1.030)	-
16	Capitalized Overhead	(10.177)	(10.177)	-
17				
18	**Depreciation and Amortization**			
19	Amortization of Deferrals	1.558	1.558	-
20	Depreciation variance on Clean Growth Projects/CPCNs/Exogenous Capital	-	(0.027)	(0.027)
21	CIAC Amortization variance on Clean Growth Projects/CPCNs/Exogenous Capital	-	0.021	0.021
22				
23	**Total Property Taxes**	17.621	17.385	(0.236)
24				
25	**Other Revenues**			
26	EV Carbon Credits	(0.625)	(0.744)	(0.119)
27				
28	**Interest Expense**			
29	Long-term debt interest expense variance	41.794	41.794	(0.000)
30	Interest variance on Clean Growth Projects/CPCNs/Exogenous Capital	-	(0.041)	(0.041)
31	Short-term debt rate variance	2.253	0.964	(1.289)
32	Short-term debt volume variance from long-term debt issue variance	(1.005)	(0.646)	0.359
33	Short-term debt timing variance from long-term debt issue timing	0.793	0.510	(0.283)
34				
35	**Income Tax Expense**			
36	Income tax variance on Clean Growth Projects/CPCNs/Exogenous Capital	-	(0.470)	(0.470)
37	Income tax/CCA rate changes	-	-	-
38	Income tax on taxable flowthrough variances above (excl. Clean Growth Projects/CPCNs/Exogenous Capital)	1.877	5.169	3.292
39				
40	**2022 Ending Deferral Account Balance True-up**			**(9.418)**

FBC provides the following explanations of the 2022 Actual variances shown in Table 12-3 above:

- The favourable variance in revenue of $11.397 million was primarily due to higher than projected residential and wholesale loads resulting largely from weather variations. Favourable variances in residential ($11.641 million), industrial ($0.270 million) and wholesale ($0.201 million) revenue were partially offset by unfavourable variances in commercial ($0.547 million), irrigation ($0.146 million) and lighting ($0.022 million) revenue;

- The increase in power purchase expense of $0.293 million was due to several factors including increased load, increased market purchases, and increased reliance on the BC Hydro PPA. Increased load and PPA purchases were primarily a result of prolonged cold weather at the end of 2022. This increase was partially offset by increased surplus capacity sales under the Capacity and Energy Purchase and Sale Agreement (CEPSA);

- The increase in wheeling costs of $0.568 million was primarily due to increased use of wheeling under BC Hydro's Open Access Transmission Tariff;

- The decrease in water fees of $0.078 million was primarily due to reduced water rental rates compared to forecast;

- The flow-through components of O&M expense were $0.011 million lower than projected, with all items comparable to the projected amounts;

- Actual property tax expense was relatively consistent with the projected amount;

- The flow-through components of other revenue were $0.119 million higher than projected, with the variance in EV Carbon Credit revenue due to approximately 329 carbon credits related to FBC's EV charging stations that were validated by BC-LCFS and monetized in 2022 but were not accounted for in the 2022 Projected amount;

- The variance between the actual (2.58 percent) and projected (4.02 percent) short-term debt interest rates results in an amount to be returned to customers of $1.289 million,[52] shown on Line 31 of the table above. There was no variance in long-term debt interest expense as actuals were as projected. The net variance of $0.076 million to be collected from customers on Lines 32 and 33 of Table 12-3 above is due to the impact of a lower actual short-term interest rate than projected;

- The unfavourable income tax variance of $3.292 million is calculated as 27 percent of the aforementioned variances; and

- The combined favourable variance of $0.517 million related to depreciation, CIAC amortization, interest and tax variances on Clean Growth/CPCN/exogenous capital amounts, shown on Lines 20, 21, 30 and 36, respectively, were derived for 2022 by comparing the actual 2022 cost of service impacts of the EV stations and the UBO, Grand Forks Terminal Station and Corra Linn projects to the amounts forecast for those same projects.

12.5 SUMMARY

FBC is not seeking any exogenous factor treatment in this Application. FBC is also not seeking approval of any new non-rate base deferral accounts but has provided an update on the Flow-through deferral account.

[52] (2.584% - 4.02%) x $89.744 million forecast 2022 short-term debt in Schedule 26 of Annual Review for 2022 Rates Compliance Filing financial schedules.

13. SERVICE QUALITY INDICATORS

13.1 INTRODUCTION AND OVERVIEW

Under the MRP, SQIs are used to monitor the Utility's performance to ensure that any efficiencies and cost reductions do not result in a degradation of the quality of service to customers.

In the MRP Decision and Order G-166-20, the BCUC approved a balanced set of SQIs for FBC, covering safety, responsiveness to customer needs, and reliability. Eight of the SQIs have benchmarks and performance ranges set by a threshold level. Four of the SQIs are for information only and as such do not have benchmarks or performance ranges.

In the subsections below, FBC reports on its 2022 and June 2023 year-to-date performance as measured against the SQI benchmarks and thresholds. In 2022, for the eight SQIs with benchmarks, six met or were better than the benchmark, with the First Contact Resolution better than the threshold and the Telephone Service Factor (Non-Emergency) lower than the threshold. For the four SQIs that are informational only, with the exception of the Average Speed of Answer results being higher due to the same challenges impacting the Telephone Service Factor (Non-Emergency), performance in 2022 for the other three informational metrics generally remains at a level consistent with prior years. In 2023 to date, performance for the metrics with benchmarks are trending towards meeting the benchmark or the threshold.

Consistent with how SQIs were reviewed during the 2014-2019 PBR Plan term,[53] FBC has provided 2022 and year-to-date 2023 SQI results in this annual review.

13.2 REVIEW OF THE PERFORMANCE OF SERVICE QUALITY INDICATORS

For each SQI, Table 13-1 provides a comparison of FBC's 2022 and June year-to-date performance for 2023 to the proposed benchmarks and thresholds approved as part of the MRP. Actual 2022 and June year-to-date results for 2023 are also provided for the four informational SQIs.

Table 13-1: Approved SQIs, Benchmarks and Actual Performance

Performance Measure	Description	Benchmark	Threshold	2022 Results	June 2023 YTD Results
Safety SQIs					
Emergency Response Time	Percent of calls responded to within two hours	>=93%	90.6%	94%	93%
All Injury Frequency Rate (AIFR)	3 year average of lost time injuries plus medical treatment injuries per 200,000 hours worked	<=1.64	2.39	1.42	1.76

[53] MRP Decision page 99: "the Panel determines that the existing approved process for interpreting metric performance is to remain in effect over the term of the MRPs."

Performance Measure	Description	Benchmark	Threshold	2022 Results	June 2023 YTD Results
Responsiveness to Customer Needs SQIs					
First Contact Resolution	Percent of customers who achieved call resolution in one call	>=78%	74%	77%	78%
Billing Index	Measure of customer bills produced meeting performance criteria	<=3.0	5.0	0.14	2.20
Meter Reading Accuracy	Number of scheduled meters that were read	>=98%	96%	99%	99%
Telephone Service Factor (Non-Emergency)	Percent of non-emergency calls answered within 30 seconds or less	>=70%	68%	65%	72%
Customer Satisfaction Index	Informational indicator - measures overall customer satisfaction	-	-	8.4	8.5
Average Speed of Answer	Informational indicator – the amount of time it takes to answer a call (seconds)	-	-	98	60
Reliability SQIs					
System Average Interruption Duration Index (SAIDI) – Normalized	Annual SAIDI (average of cumulative customer outage time)	3.22[54]	4.52	2.42	3.21
System Average Interruption Frequency Index (SAIFI) - Normalized	Annual SAIFI (average customer outage)	1.57	2.19	1.52	1.48
Generator Forced Outage Rate	Informational indicator – Percent of time a generating unit is removed from service due to component failure or other events.	-	-	0.50%	0.65%
Interconnection Utilization	Informational indicator – percent of time that an interconnection point was available and providing electrical service to wholesale customers.	-	-	99.94%	99.98%

In the following sections, FBC reviews each SQI's year-to-date individual performance in 2022 and 2023. Discussion is also provided for the informational SQIs.

[54] Benchmarks and thresholds for SAIDI and SAIFI were approved in the FBC Annual Review for 2020 and 2021 Rates Decision and Order G-42-21.

13.2.1 Safety Service Quality Indicators

13.2.1.1 Emergency Response Time

Emergency Response Time is the time elapsed from the initial identification of a loss of electrical power (via a customer call or internal notification) to the arrival of FBC personnel on site at the trouble location. This metric provides ongoing information to assess FBC crew sizes and crew locations in response to system trouble. The target measures the percentage of emergency calls responded to within two hours. The measure is calculated as follows:

$$\frac{\text{Number of emergency calls responded to within two hours}}{\text{Total number of emergency calls in the year}}$$

There are many variables affecting the response time, including time of day (i.e., during business hours or after business hours), number and type of events (i.e., widespread outages), available resources, location (i.e., travel times and traffic congestion) and weather conditions.

The 2022 result was 94 percent which was better than the benchmark. The June 2023 year-to-date performance is 93 percent, which meets the benchmark.

For comparison, the Company's annual results under the 2014-2019 PBR Plan, the 2020, 2021, and 2022 results and the June 2023 year-to-date emergency response time results are provided below. While the results have been relatively consistent, variables such as the location and severity of outage and the number of trouble calls contribute to the observed volatility in the annual performance for this metric.

Table 13-2: Historical Emergency Response Time

Description	2014	2015	2016	2017	2018	2019	2020	2021	2022	June 2023 YTD
Results	91%	92%	97%	93%	94%	92%	92%	93%	94%	93%
Benchmark	93%									
Threshold	90.6%									

13.2.1.2 All Injury Frequency Rate

The All Injury Frequency Rate (AIFR) is an employee safety performance indicator based on injuries per 200,000 hours worked, with injuries defined as lost time injuries (i.e., one or more days missed from work) and medical treatments (i.e., medical treatment was given or prescribed). The annual performance for this metric is calculated as:

$$\frac{\text{Number of Employee Injuries x 200,000 hours}}{\text{Total Exposure Hours Worked}}$$

For the purpose of this SQI, the measurement of performance is based on the three-year rolling average of the annual results.

The 2022 (three-year rolling average) result was 1.42 which was better than the benchmark of 1.64. The 2022 annual AIFR was 2.60 which reflected 4 Medical Treatments and 8 Lost Time Injuries. The increase in AIFR was particularly prevalent in Q4 2022, after a sudden change in winter conditions led to a notable spike in slips, trips, and falls resulting in more serious injuries. FBC responded to this by issuing an immediate safety alert (Safely Navigating Winter Conditions) to all field employees, which was also reviewed at all safety meetings, and providing access to traction aids throughout Operations.

The June 2023 year-to-date performance (three-year rolling average) result is 1.76 which is better than the threshold. The June 2023 year-to-date performance (annual) is 2.54 and reflects 3 Medical Treatments and 3 Lost Time Injuries. Thus far in 2023, FBC continues to see an increase in total minor preventable injuries, predominately those sustained while performing activities involving repetitive work and/or awkward positioning. FBC has responded to this by engaging its Ergonomist and Injury Prevention Specialist to provide more education and treatment throughout the Company. FBC also hired an Injury Management Specialist to provide proactive educational sessions, as well as customized Recover at Work plans for employees. In addition, FBC has implemented customized ergonomics courses for some of the higher risk areas.

Strengthening the safety culture continues to be a key driver for FBC, building on the commitment to learn from safety events, identify safety hazards, assess risk and continually improve the safety management system through the implementation and sustainment of robust safety defences and controls.

For comparison, the Company's results under the 2014 to 2019 PBR Plan, the 2020, 2021 and 2022 results and the June year-to-date AIFR results are provided below.

Table 13-3: Historical All Injury Frequency Rate Results

Description	2014	2015	2016	2017	2018	2019	2020	2021	2022	June 2023 YTD
Annual Results	3.21	1.54	1.15	1.13	1.56	0.46	0.66	0.89	2.60	2.54
Three year rolling average	2.58	2.52	1.97	1.27	1.28	1.06	0.87	0.67	1.42	1.76
Benchmark	1.64									
Threshold	2.39									

13.2.2 Responsiveness to Customer Needs Service Quality Indicators

13.2.2.1 First Contact Resolution

First Contact Resolution (FCR) measures the percentage of customers who receive resolution to their issue in one contact with FBC. The Company determines the FCR results using a customer survey, tracking the number of customers who responded that their issue was resolved in the first contact with the Company. The FCR rate is impacted by factors such as the quality and

effectiveness of the Company's coaching and training programs and the composition of the different call drivers.

The 2022 result was 77 percent which was better than the threshold of 74 percent. The reduction in FCR for 2022 as compared to previous years, as shown in Table 13-4 below, is largely attributable to the increased volume of high bill inquiries. Depending on the nature of the high bill, there may be a need for customers to follow up on their bill, resulting in more than one contact to resolve their concerns. As well, high bill calls can require longer-term payment arrangements which at times may require changes, leading to customers connecting with FBC multiple times for the same reason. The June 2023 year-to-date performance is 78 percent which meets the benchmark.

For comparison, the Company's results under the 2014 to 2019 PBR Plan, the 2020, 2021 and 2022 results and the June 2023 year-to-date results are provided below.

Table 13-4: Historical First Contact Resolution Levels

Description	2014	2015	2016	2017	2018	2019	2020	2021	2022	June 2023 YTD
Annual Results	73%	76%	79%	80%	82%	82%	82%	82%	77%	78%
Benchmark	78%									
Threshold	72%						74%			

13.2.2.2 Billing Index

The Billing Index indicator tracks the effectiveness of the Company's billing system by measuring the percentage of customer bills produced meeting performance criteria. The Billing Index is a composite index with three components:

- Billing completion (percent of accounts billed within two days of the billing due date);
- Billing timeliness (percent of invoices delivered to Canada Post within two days of file creation); and
- Billing accuracy (percent of bills without a production issue based on input data).

The objective is to achieve a score of five or less.

The Billing Index is impacted by factors such as the performance of the Company's billing system, weather variability, which can cause a high volume of billing checks and estimation issues, and mail delivery by Canada Post.

The 2022 result was 0.14 which was better than the benchmark of 3.0. No significant billing issues occurred in 2022. The June 2023 year-to-date result of 2.20 is attributable to a technical issue experienced in February which resulted in a timing delay between the creation of the bills and those bills being sent to the print vendor. This technical issue has been corrected.

The 2022 Billing Index sub-measures calculation is as follows.

Table 13-5: Calculation of 2022 Billing Index

Billing sub-measure	Percent Achieved (PA)	Formula		Result
Billing Accuracy (Percent of bills without a Production Issue, based on input data); Target: 99.9%	100.00%	If (PA≥99.9%,5000*(1 - PA),100*(1.05-PA))	=5000*(1-100%)	0.00
Billing Timeliness (Percent of invoices delivered to Canada Post within 2 days of file creation); Target: 95%	100.00%	(100%-PA)*100	=(100%-100%)*100	0.00
Billing Completion (Percent of accounts billed within 2 days of the billing due date); Target: 95%	99.57%	(100%-PA)*100	=(100%-99.57%)*100	0.43
Billing Service Quality Indicator; Target < 3.0		(Accuracy PA+Timeliness PA+Completion PA)/3	=(0.+0+0.43) /3	0.14

For comparison, the Company's results under the 2014 to 2019 PBR Plan, the 2020, 2021 and 2022 results and the June 2023 year-to-date results are provided below.

Table 13-6: Historical Billing Index Results

Description	2014	2015	2016	2017	2018	2019	2020	2021	2022	June 2023 YTD
Annual Results	2.34	0.39	0.57	0.15	0.29	1.96	0.13	0.12	0.14	2.20
Benchmark	5.0						3.0			
Threshold	5.0									

13.2.2.3 Meter Reading Accuracy

This SQI compares the number of meters that are read to those scheduled to be read. Providing accurate and timely meter reads for customers is a key driver for the Company and its customers. The results are calculated as:

$$\frac{\text{Number of scheduled meters read}}{\text{Number of scheduled meters for reading}}$$

The 2022 result was 99 percent, which was better than the benchmark of 98 percent. The June 2023 year-to-date result is 99 percent, which is better than the benchmark.

For comparison, the Company's results under the 2014 to 2019 PBR Plan, the 2020, 2021 and 2022 results and the June 2023 year-to-date results are provided below.

Table 13-7: Historical Meter Reading Accuracy Results

Description	2014	2015	2016	2017	2018	2019	2020	2021	2022	June 2023 YTD
Annual Results	98%	96%	99%	99%	99%	99%	99%	99%	99%	99%
Benchmark	97%						98%			
Threshold	94%						96%			

13.2.2.4 Telephone Service Factor (Non-Emergency)

The Telephone Service Factor (Non-Emergency) measures the percentage of non-emergency calls that are answered in 30 seconds. It is calculated as:

$$\frac{\text{Number of non-emergency calls answered within 30 seconds}}{\text{Number of non-emergency calls received}}$$

The TSF is a measure of how well the Company can balance costs and service levels with the overall objective to maintain a consistent TSF level. This ensures the Company is staying within appropriate cost levels and maintaining adequate service for its customers. The principal factors influencing the TSF results include volume and type of inbound calls received and the resources available to answer those calls. Staffing is matched to the expected call volume based on historical data in order to reach the service level benchmark desired. Other factors that can influence the TSF are billing system related issues and weather patterns that may generate high numbers of billing related queries and the complexity of the calls.

The 2022 result was 65 percent, which was lower than the threshold. The June 2023 year-to-date performance is 72 percent, which is better than the benchmark.

FBC experienced several challenging circumstances in 2022 that contributed to the year-end performance being below the threshold. These challenges included higher than expected attrition being experienced in the contact centre, compounded by an increased amount of high bill inquiries in the first and fourth quarters. Each of these is described further below.

Customer Service is experiencing higher than expected levels of attrition, having lost approximately 40 percent of its Customer Service Representatives in 2022, compared to 20 percent in 2021.[55] Exits in 2021 occurred during the third and fourth quarters, resulting in fewer and less experienced employees prepared to support call volumes at the start of 2022. Additionally, 2022 exits were spread throughout 2022 with the majority in the first and fourth quarters. To mitigate the impact of this attrition, FBC accelerated the timing of planned new hire

[55] On average, FBC has approximately 20 customer service representatives, and 8 left the organization in 2022 and 4 in 2021. This compares to typical annual attrition in the range of 1-2 customer service representatives from the organization.

classes as well as the size of new hire classes in 2021, 2022 and 2023. While some success was achieved, FBC continued to face challenges recruiting and retaining newly hired contact centre employees in 2022. In addition, it takes approximately 12 months for new employees to be proficient and fully trained to support all customer inquiries and calls, and as such, average call handle times remain higher than normal while a greater portion of employees gain this experience.

High bill inquiries are expected in the first quarter of the year and planned for with staffing levels and schedules adjusted, new hire classes timed accordingly, and refresher training offered to those employees who may need it. However, the colder temperatures resulted in a volume of high bill inquiries that was greater than anticipated and lasted longer than typical. This particular call type is often longer in duration and may also result in follow-up work and investigation. Compounded by attrition, there were fewer and less experienced employees prepared to support these types of calls, resulting in overall longer average wait times and a lower percentage of calls answered within 30 seconds or less.

The additional hiring and training classes in 2023 have proven to be successful, with year-to-date performance better than the benchmark. Additionally, the customer service index has remained high throughout 2022 and 2023 year-to-date, indicating that the focus on first contact resolution continues to result in an overall high quality of service being experienced by customers.

For comparison, the Company's results under the 2014 to 2019 PBR Plan, the 2020, 2021 and 2022 results and the June 2023 year-to-date results are provided below. As discussed in the Annual Review for 2015 Rates, the 2014 result was negatively impacted by events such as the first verified meter readings occurring after the IBEW labour disruption ended in December 2013, introduction of the Residential Conservation Rate, and the integration of the City of Kelowna customers.

Table 13-8: Historical TSF (Non-Emergency) Results

Description	2014	2015	2016	2017	2018	2019	2020	2021	2022	June 2023 YTD
Annual Results	48%	71%	70%	70%	72%	70%	70%	70%	65%	72%
Benchmark	70%									
Threshold	68%									

13.2.2.5 Customer Satisfaction Index

The Customer Satisfaction Index (CSI) is an informational indicator that measures overall customer satisfaction with the Company. The index reflects customer feedback about important service touch points including the contact centre, perceived accuracy of meter reading, energy conservation information and field services. The index includes feedback from both residential and commercial customers. The survey is conducted quarterly, and results are presented as a score out of 10.

The CSI survey investigates service quality as well as customer attitudes that are often influenced by factors outside the Company's control. Important examples include storm-related unplanned outages and media coverage.

The annual CSI score for 2022 was 8.4, consistent with 2021. There were no statistically significant shifts from 2021 to 2022 in the five measures that make up the overall customer satisfaction score. The score for the accuracy of meter reading metric increased from 8.2 in 2021 to 8.3 in 2022. The score for the satisfaction with energy conservation information metric decreased from 7.5 in 2021 to 7.4 in 2022. In addition, the scores for overall satisfaction, satisfaction with the contact centre and field services metrics remained static at 8.4, 8.4, and 9.0 in 2022, respectively.

The score for 2023 year-to-date is 8.5, slightly higher than the annual score recorded for 2022. Of the five measures that make up the overall customer satisfaction score, the results for June 2023 year-to-date were higher in three areas and static in two when compared to the annual 2022 scores. The scores for the satisfaction with energy conservation, contact centre, and field services metrics increased from 7.4 to 7.5, 8.4 to 8.5, and 9.0 to 9.2, respectively. The scores for the overall satisfaction and satisfaction with the accuracy of meter reading metrics remained static at 8.4 and 8.3, respectively, from results achieved in 2022. None of these changes are statistically significant.

For comparison, the Company's results under the 2014 to 2019 PBR Plan, the 2020, 2021 and 2022 results and the June 2023 year-to-date results are provided below.

Table 13-9: Historical Customer Satisfaction Results

Description	2014	2015	2016	2017	2018	2019	2020	2021	2022	June 2023 YTD
Annual Results	8.1	8.1	8.2	8.2	8.3	8.5	8.5	8.4	8.4	8.5
Benchmark	n/a									
Threshold	n/a									

13.2.2.6 Average Speed of Answer

The Average Speed of Answer (ASA) is an informational indicator that measures the amount of time it takes for a customer service representative to answer a customer's call (seconds).

The 2022 result was 98 seconds, and the June 2023 year-to-date performance is 60 seconds.

2022 performance reflects the challenging circumstances described above for the Telephone Service Factor (Non-Emergency). Recovery of the ASA commenced in March 2023 with monthly ASA performance returning to typical levels of approximately 1 minute. This is expected to continue through the remainder of the year.

For comparison, the Company's results under the 2014 to 2019 PBR Plan, the 2020, 2021 and 2022 results and the June 2023 year-to-date results are provided below.[56]

Table 13-10: Average Speed of Answer

Description	2014	2015	2016	2017	2018	2019	2020	2021	2022	June 2023 YTD
Annual Results	226	49	48	49	49	49	71	65	98	60
Benchmark	n/a									
Threshold	n/a									

13.2.3 Reliability Service Quality Indicators

FBC measures transmission and distribution system reliability according to the Institute of Electrical and Electronics Engineers (IEEE) method of normalizing reliability statistics by excluding "major events". Major events are identified as those that cause outages exceeding a threshold number of customer-hours. Threshold values are calculated by applying a statistical method called the "2.5 Beta" adjustment to historical reliability data. Any single outage event that exceeds the threshold value is excluded from the reliability data. Excluding major events allows them to be studied separately and reveals trends in daily operations that would be hidden or skewed if they were included in the data set. Major event days in the FBC service territory have been caused by mudslides, wind or snow storms, and wildfires.

Reported outages included in these measures are of one minute or longer in duration, which is consistent with the Canadian Electricity Association (CEA) standard for reporting.

13.2.3.1 System Average Interruption Duration Index (SAIDI) – Normalized

SAIDI is the amount of time the average customer's power is off during the year (i.e., the total amount of time the average customer's clock would lose during a year), after adjusting for the impact of major events as described above, and is calculated as follows:

$$\frac{\text{Total Customer Hours of Interruption}}{\text{Total Number of Customers Served}}$$

Customer Hours of Interruption related to a power outage are calculated by multiplying the number of customers affected by the outage by the duration of the outage.

For the purpose of this SQI, the measurement of performance is based on the annual results.

The 2022 result was 2.42 which was better than the benchmark of 3.22. The June 2023 year-to-date performance is 3.21 which is better than the benchmark. The 2022 results improved

[56] ASA in 2014 is higher than other years due to the impact of the six months of job action that took place in Q3 and Q4 of 2013. This job action resulted in a higher number of bill estimates, which led to a higher volume of customer inquiries in 2014 as bill adjustments were made reflecting actual meter reads.

compared to 2021 due to the absence of multiple external factors (i.e., fires, storms, collapse of crane incident in Kelowna in 2021)[57] which negatively impacted the 2021 SAIDI results.

There were no Major Event Days that met the threshold for normalization in 2022, and one Major Event Day in 2023 year-to-date. On May 21, 2023, a windstorm impacted the Kootenay region (centered in Salmo) resulting in outages to over 13,500 customers for a total of just under 46,200 customer hours lost.

For comparison, the Company's results under the 2014 to 2019 PBR Plan, the 2020, 2021 and 2022 results and the June 2023 year-to-date results are provided below. From 2014 to 2019, the benchmark and the threshold reflect the values established under the PBR Plan using three-year rolling average results. Starting in 2020, the benchmark and threshold reflect the values approved by the BCUC for the MRP term.[58]

Table 13-11: Historical SAIDI Results

Description	2014	2015	2016	2017	2018	2019	2020	2021	2022	June 2023 YTD
Annual normalized results	2.32	2.13	2.10	4.05	3.15	2.45	3.17	4.27	2.42	3.21
Benchmark	2.22						3.22			
Threshold	2.62						4.52			

13.2.3.2 System Average Interruption Frequency Index (SAIFI) – Normalized

SAIFI is the average number of interruptions per customer served per year (i.e., the number of times the average customer would have to reset their clock during the year), after adjusting for the impact of major events as described above, and is calculated as follows:

$$\frac{\text{Total Number of Customer Interruptions}}{\text{Total Number of Customers Served}}$$

The Number of Customer Interruptions related to a power outage is the number of customers affected by the outage.

For the purpose of this SQI, the measurement of performance is based on the annual results.

The 2022 result was 1.52 which was better than the benchmark, and the June 2023 year-to-date performance is 1.48 which is also better than the benchmark. The 2022 SAIFI results improved compared to 2021 due to the absence of the same multiple external factors (i.e., fires, storms and collapse of crane incident in Kelowna in 2021) discussed in the SAIDI section above.

[57] Refer to the FBC Annual Review for 2023 Rates, pages 140-141 for further details.
[58] The benchmark and threshold for SAIDI were approved in the FBC Annual Review for 2020 and 2021 Rates Decision and Order G-42-21.

For comparison, the Company's results under the 2014 to 2019 PBR Plan, the 2020, 2021 and 2022 results and the June 2023 year-to-date results are provided below. From 2014 to 2019, the benchmark and the threshold reflect the values established under the PBR Plan using three-year rolling average results. Starting in 2020, the benchmark and threshold reflect the values approved by the BCUC for the MRP term.[59]

Table 13-12: Historical SAIFI Results

Description	2014	2015	2016	2017	2018	2019	2020	2021	2022	June 2023 YTD
Annual normalized results	1.64	1.56	1.34	1.78	1.73	1.21	1.64	2.08	1.52	1.48
Benchmark	1.64						1.57			
Threshold	2.50						2.19			

13.2.3.3 Generator Forced Outage Rate

Generator Forced Outage Rate (GFOR), an informational indicator, is a measure of the percentage of time in one year that the generating units experienced forced outages compared to the amount of time they could have operated without a forced outage. A forced outage means the removal of a generating unit from service due to the occurrence of a component failure or other event, making it unavailable to produce power due to the unexpected breakdown. The GFOR is defined by the CEA as follows:

$$\frac{\text{Total Forced Outage Time}}{\text{Total Forced Outage Time + Total Operating Time}} \text{ X } 100$$

The 2022 result for GFOR was 0.50 percent. The June 2023 year-to-date performance is 0.65 percent.

For comparison, the Company's results under the 2014 to 2019 PBR Plan, the 2020, 2021 and 2022 results and the June 2023 year-to-date results are provided below.

Table 13-13: Historical Generator Forced Outages

	2014	2015	2016	2017	2018	2019	2020	2021	2022	June 2023 YTD
FBC	1.7%	0.1%	0.8%	0.6%	0.4%	0.1%	1.3%	0.2%	0.5%	0.65%
CEA	6.3%	6.2%	6.2%	6.2%	6.7%	4.9%	4.6%	5.0%	TBD	

[59] The benchmark and threshold for SAIFI were approved in the FBC Annual Review for 2020 and 2021 Rates Decision and Order G-42-21.

13.2.3.4 Interconnection Utilization

Interconnection Utilization, an informational indicator, is a measurement of the time that an interconnection point was available and providing electrical service to the municipal wholesale customers (City of Penticton, City of Summerland, City of Grand Forks and City of Nelson). There are 12 points of interconnection combined between the four customers.

The Interconnection Utilization metric for the interconnection points listed is calculated as follows:

$$\frac{\text{Total Operating Hours}}{\text{Total Operating Hours + Total Outage Time}}$$

The 2022 result of 99.94 percent and June 2023 year-to-date result of 99.98 percent are generally consistent with prior years' results. There were no notable major events in 2022 that impacted the interconnection utilization performance. For comparison, the Company's results under the 2014 to 2019 PBR Plan, the 2020, 2021 and 2022 results and the June 2023 year-to-date results are provided below.

Table 13-14: Interconnection Utilization

Description	2014	2015	2016	2017	2018	2019	2020	2021	2022	June 2023 YTD
Interconnection Utilization	99.99%	99.94%	99.99%	99.95%	99.96%	99.98%	99.89%	99.90%	99.94%	99.98%
Benchmark	n/a									
Threshold	n/a									

13.3 SUMMARY

In summary, FBC's 2022 and June 2023 year-to-date SQI results indicate that the Company's overall performance is representative of a high level of service quality. In 2022, for the eight SQIs with benchmarks, six met or were better than the benchmark with one, First Contact Resolution, better than the threshold and the Telephone Service Factor (Non-Emergency) lower than the threshold. For the four SQIs that are informational only, with the exception of the Average Speed of Answer results being higher, performance in 2022 for the other three informational metrics generally remains at a level consistent with prior years.

Appendix A

LOAD FORECAST SUPPLEMENTARY INFORMATION

Table A1-1: Consumer Price Index (CPI)

Reference period	
	2002=100
July 2021	136.7
August 2021	137.0
September 2021	137.2
October 2021	137.9
November 2021	138.1
December 2021	138.0
January 2022	139.4
February 2022	140.4
March 2022	143.0
April 2022	144.2
May 2022	146.1
June 2022	146.5
July 2022	147.6
August 2022	147.0
September 2022	147.8
October 2022	148.6
November 2022	148.1
December 2022	147.1
January 2023	148.1
February 2023	149.1
March 2023	149.7
April 2023	150.4
May 2023	151.0
June 2023	151.6

Table A1-2: Average Weekly Earnings (AWE)

Reference period	
	Dollars
July 2021	1,143.76[B]
August 2021	1,143.96[B]
September 2021	1,142.37[B]
October 2021	1,140.94[B]
November 2021	1,129.51[B]
December 2021	1,132.93[B]
January 2022	1,155.32[B]
February 2022	1,153.57[B]
March 2022	1,161.00[B]
April 2022	1,164.51[B]
May 2022	1,159.89[B]
June 2022	1,167.14[B]
July 2022	1,162.26[B]
August 2022	1,171.52[B]
September 2022	1,171.94[B]
October 2022	1,174.29[B]
November 2022	1,176.97[B]
December 2022	1,153.31[B]
January 2023	1,180.04[B]
February 2023	1,175.83[B]
March 2023	1,191.20[B]
April 2023	1,199.14[B]

Table A1-3: British Columbia Three-Year Outlook 2023

Key Economic Indicators: British Columbia, 2022–25
(forecast completed February 6, 2023)

	2023Q1	2023Q2	2023Q3	2023Q4	2024Q1	2024Q2	2024Q3	2024Q4	2025Q1	2025Q2	2025Q3	2025Q4	2022	2023	2024	2025
GDP at market prices ($ millions)	391,736	395,415	399,177	403,736	406,355	410,776	415,451	420,228	424,501	428,452	432,006	435,380	387,452	397,516	413,202	430,085
	0.8	*0.9*	*1.0*	*1.1*	*0.6*	*1.1*	*1.1*	*1.1*	*1.0*	*0.9*	*0.8*	*0.8*	*10.5*	*2.6*	*3.9*	*4.1*
GDP at market prices (2012 $ millions)	288,445	288,783	289,747	291,630	293,450	295,974	298,578	301,260	303,505	305,509	307,230	308,858	288,561	289,651	297,315	306,276
	-0.4	*0.1*	*0.3*	*0.6*	*0.6*	*0.9*	*0.9*	*0.9*	*0.7*	*0.7*	*0.6*	*0.5*	*2.3*	*0.4*	*2.6*	*3.0*
GDP at basic prices (2012 $ millions)	268,952	269,263	270,150	271,927	273,661	276,038	278,453	280,981	283,105	284,983	286,596	288,138	268,886	270,073	277,283	285,705
	-0.4	*0.1*	*0.3*	*0.7*	*0.6*	*0.9*	*0.9*	*0.9*	*0.8*	*0.7*	*0.6*	*0.5*	*2.4*	*0.4*	*2.7*	*3.0*
Consumer price index (2002 = 1.000)	1.494	1.511	1.518	1.525	1.537	1.547	1.553	1.559	1.567	1.578	1.584	1.590	1.455	1.512	1.549	1.580
	1.0	*1.1*	*0.5*	*0.5*	*0.8*	*0.6*	*0.4*	*0.4*	*0.6*	*0.7*	*0.4*	*0.4*	*6.9*	*3.9*	*2.4*	*2.0*
Implicit price deflator—GDP at market prices	1.358	1.369	1.378	1.384	1.385	1.388	1.391	1.395	1.399	1.402	1.406	1.410	1.343	1.372	1.390	1.404
(2012 = 1.000)	*1.1*	*0.8*	*0.6*	*0.5*	*0.0*	*0.2*	*0.3*	*0.2*	*0.3*	*0.3*	*0.3*	*0.2*	*8.1*	*2.2*	*1.3*	*1.0*
Wages and salary per employee ($ 000s)	62.6	63.0	63.4	63.9	64.3	64.7	65.2	65.5	65.8	66.2	66.6	66.9	61.3	63.2	64.9	66.4
	1.4	*0.6*	*0.6*	*0.8*	*0.7*	*0.6*	*0.6*	*0.6*	*0.4*	*0.6*	*0.6*	*0.6*	*7.5*	*3.2*	*2.7*	*2.2*
Primary household income ($ millions)	271,333	273,731	277,762	281,397	284,854	288,183	291,553	294,696	297,304	300,218	303,091	306,018	263,680	276,056	289,821	301,658
	1.0	*0.9*	*1.5*	*1.3*	*1.2*	*1.2*	*1.2*	*1.1*	*0.9*	*1.0*	*1.0*	*1.0*	*9.3*	*4.7*	*5.0*	*4.1*
Household disposable income ($ millions)	238,251	238,085	241,327	244,400	246,131	248,862	251,726	254,524	256,290	258,790	261,242	263,730	230,486	240,516	250,311	260,013
	0.8	*-0.1*	*1.4*	*1.3*	*0.7*	*1.1*	*1.2*	*1.1*	*0.7*	*1.0*	*0.9*	*1.0*	*6.4*	*4.4*	*4.1*	*3.9*
Household net savings rate (per cent)	6.5	5.4	5.4	5.3	5.0	4.9	4.8	4.8	4.7	4.6	4.7	4.7	5.1	5.6	4.9	4.7
Population (000s)	5,395	5,422	5,447	5,472	5,496	5,519	5,542	5,564	5,586	5,608	5,631	5,652	5,303	5,434	5,530	5,619
	0.5	*0.5*	*0.5*	*0.5*	*0.4*	*0.4*	*0.4*	*0.4*	*0.4*	*0.4*	*0.4*	*0.4*	*2.1*	*2.5*	*1.8*	*1.6*
Employment (000s)	2,767	2,766	2,781	2,794	2,804	2,816	2,827	2,837	2,847	2,857	2,866	2,875	2,748	2,777	2,821	2,861
	0.3	*0.0*	*0.6*	*0.4*	*0.4*	*0.4*	*0.4*	*0.4*	*0.3*	*0.3*	*0.3*	*0.3*	*3.1*	*1.0*	*1.6*	*1.4*
Labour force (000s)	2,910	2,916	2,929	2,939	2,949	2,959	2,969	2,979	2,989	2,999	3,008	3,017	2,880	2,923	2,964	3,003
	0.9	*0.2*	*0.4*	*0.4*	*0.3*	*0.3*	*0.4*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*1.0*	*1.5*	*1.4*	*1.3*
Labour force participation rate (per cent)	64.3	64.1	64.1	64.0	64.0	63.9	63.9	63.8	63.8	63.7	63.7	63.6	64.9	64.1	63.9	63.7
Unemployment rate (per cent)	4.9	5.1	5.0	4.9	4.9	4.8	4.8	4.8	4.8	4.7	4.7	4.7	4.6	5.0	4.8	4.7
Retail sales ($ millions)	100,889	101,567	102,870	104,222	105,539	106,986	108,360	109,565	110,577	111,794	112,829	113,854	101,049	102,387	107,613	112,263
	0.0	*0.7*	*1.3*	*1.3*	*1.3*	*1.4*	*1.3*	*1.1*	*0.9*	*1.1*	*0.9*	*0.9*	*2.5*	*1.3*	*5.1*	*4.3*
Housing starts (units, 000s)	39,451	38,118	38,500	40,000	42,000	43,584	43,850	43,838	43,692	43,528	43,340	43,127	46,721	39,017	43,318	43,422
	-23.3	*-3.4*	*1.0*	*3.9*	*5.0*	*3.8*	*0.6*	*0.0*	*-0.3*	*-0.4*	*-0.4*	*-0.5*	*-1.9*	*-16.5*	*11.0*	*0.2*
Net interprovincial migration (000s)	15.2	17.7	16.3	16.8	17.0	17.3	17.5	17.8	18.0	18.3	18.5	18.8	12	16.5	17.4	18.4
Net international migration (000s)	89.7	85.5	81.8	78.9	76.5	74.6	73.1	72.0	72.3	71.6	71.0	70.5	118.4	84.0	74.1	71.3

Shaded area represents forecast data, *italics indicate percentage change*.
All data are in millions of dollars, seasonally adjusted at annual rates, unless otherwise specified.
For each indicator, the first line is the level and the second line is the percentage change from the previous period.
Sources: The Conference Board of Canada; Statistics Canada; CMHC Housing Time Series Database.

Note: Table above is from the Conference Board of Canada, British Columbia Three-Year Outlook, March 31, 2023.

Appendix A2

Load Forecast Tables

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1. INTRODUCTION

This appendix provides the historical and forecast load data used in Section 3 of the Application. The tables in Section 2 of this appendix show 10 years of historical data and the before-savings and after-savings forecast for 2023S and 2024F. Section 3 shows the customer forecast data while Section 4 presents the residential UPC data. The tables in Section 5 show the load forecast. Table 5.3 shows the DSM that was deducted from the before-savings forecast to provide the after-savings forecast for 2024F. Tables 6.1 and 6.2 show the variance of the customer accounts and forecasts from 2017 to 2022 when compared to the actuals. Table 6.3 shows the annual growth of customer and load that FBC has experienced since 2017. Tables 6.4 and 6.5 show the Residential UPC and Winter peak variances from forecast from 2020 to 2022. Finally, Table 6.6 shows the system load factor from the years 2017 to 2022 and the forecast load factor for 2023S and 2024F.

The tables in this appendix reflect the acquisition by FBC of the assets and customers of the City of Kelowna electric utility effective March 31, 2013. The acquisition resulted in an increase in direct customers to FBC and a re-distribution of load from wholesale to other rate classes in 2013 and 2014.

2. MONTHLY LOAD FORECAST

Forecast loads are shown:

- before-savings – the load before DSM and includes Normalized loads to December 2022.
- after-savings – the load after DSM and includes Normalized loads to December 2022.

2.1 GROSS LOAD (MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Historic Loads													
2013	372,939	327,919	300,296	255,888	249,987	235,093	291,183	274,786	241,239	266,317	303,923	380,406	3,499,975
2014	363,245	306,420	303,949	253,146	241,945	242,396	285,626	270,799	229,532	256,624	301,612	380,684	3,435,977
2015	364,636	317,325	299,476	250,366	249,815	247,921	287,307	276,774	233,611	256,959	300,534	361,093	3,445,816
2016	362,417	311,090	292,322	268,567	248,286	243,400	287,329	280,865	234,850	266,011	328,783	352,683	3,476,603
2017	364,284	298,155	307,568	263,749	249,610	251,126	300,242	289,240	246,675	265,495	324,809	356,765	3,517,718
2018	373,759	312,050	306,251	264,157	273,363	256,750	308,108	296,176	231,268	262,444	302,321	372,719	3,559,367
2019	371,601	294,208	316,259	261,193	267,746	257,893	295,882	292,659	260,751	291,966	314,389	370,267	3,594,813
2020	380,978	331,422	304,284	246,809	239,849	247,702	308,135	302,775	260,553	282,819	332,127	373,313	3,610,765
2021	379,923	340,308	320,380	275,424	255,599	264,059	313,426	294,626	255,445	284,819	333,861	374,965	3,692,835
2022	395,393	344,739	328,117	275,896	259,774	274,145	317,727	309,709	265,171	280,605	337,000	396,554	3,784,830
Before-Savings													
2023S	393,099	343,506	322,822	275,878	267,544	279,101	319,086	308,550	269,588	290,246	343,143	391,122	3,803,684
2024F	395,405	345,601	324,885	277,934	269,596	281,241	321,367	310,778	271,994	292,344	345,298	393,394	3,829,838
After-Savings													
2023S	390,501	340,929	320,309	273,448	265,202	276,815	316,824	306,260	267,245	287,810	340,630	388,565	3,774,539
2024F	390,223	340,479	319,905	273,132	264,983	276,752	316,937	306,307	267,435	287,618	340,441	388,467	3,772,679

2.2 NET LOAD (MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Historic Loads													
2013	337,728	297,641	276,667	237,842	233,199	219,696	268,867	254,751	225,078	247,419	279,078	343,897	3,221,865
2014	329,517	279,546	279,656	235,365	226,070	226,002	263,980	251,199	214,732	238,897	276,987	343,940	3,165,892
2015	330,474	288,500	275,700	232,842	232,855	230,716	265,292	256,237	218,219	239,080	275,925	327,535	3,173,373
2016	328,972	283,576	269,823	248,799	231,696	226,952	265,539	259,978	219,469	247,136	300,036	320,866	3,202,843
2017	330,163	272,433	282,574	244,425	232,665	233,492	276,339	266,935	229,621	246,479	296,394	323,921	3,235,440
2018	338,459	284,446	281,783	245,037	253,552	238,619	283,364	273,179	216,362	244,085	277,755	337,598	3,274,238
2019	336,960	269,648	290,510	242,633	248,852	239,769	273,123	270,359	242,250	269,764	288,203	335,853	3,307,924
2020	345,128	301,193	280,588	230,312	224,658	231,093	283,880	279,297	242,295	262,137	303,482	338,771	3,322,834
2021	344,200	308,531	294,270	255,141	238,455	245,309	288,355	272,273	237,823	263,831	304,896	340,091	3,393,175
2022	356,904	312,144	300,781	255,512	242,069	254,001	291,969	285,142	246,240	260,155	307,481	357,859	3,470,257
Before-Savings													
2023S	356,862	312,701	297,618	256,528	249,790	259,327	294,420	285,377	251,055	269,568	314,129	355,218	3,502,592
2024F	358,989	314,632	299,533	258,433	251,695	261,304	296,522	287,433	253,266	271,513	316,120	357,317	3,526,758
After-Savings													
2023S	354,461	310,320	295,296	254,283	247,626	257,215	292,330	283,261	248,891	267,317	311,807	352,855	3,475,662
2024F	354,202	309,899	294,931	253,996	247,433	257,156	292,429	283,302	249,053	267,146	311,631	352,765	3,473,943

2.3 RESIDENTIAL (MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Historical Normalized Actuals													
2013	145,263	115,730	114,637	112,100	90,869	85,319	120,666	100,397	73,591	97,867	124,661	171,845	1,352,945
2014	147,191	120,724	129,852	84,813	80,792	77,673	105,443	102,753	73,260	95,314	119,531	159,107	1,296,452
2015	150,230	122,084	120,304	91,957	76,652	84,441	110,145	97,235	73,384	99,324	125,839	146,556	1,298,150
2016	147,429	121,286	113,080	99,963	91,648	85,702	101,212	96,335	77,431	96,417	129,741	135,335	1,295,580
2017	145,663	112,986	118,857	102,166	94,155	86,021	106,392	95,082	82,012	96,745	129,829	150,584	1,320,492
2018	154,740	121,081	119,975	97,261	100,276	86,146	109,349	100,153	70,342	89,942	112,695	150,638	1,312,598
2019	147,714	98,552	116,377	90,039	91,727	81,739	100,157	94,674	87,612	98,618	112,609	146,320	1,266,137
2020	150,634	126,164	117,219	93,211	89,289	91,128	111,958	103,644	86,533	100,913	126,958	149,181	1,346,832
2021	151,923	132,351	117,698	95,324	88,510	89,335	114,977	114,763	58,293	98,449	123,064	145,645	1,330,331
2022	150,247	130,107	119,338	92,786	83,362	90,463	111,776	99,512	80,706	95,008	120,814	146,242	1,320,362
Before-Savings													
2023S	148,630	127,563	116,282	92,342	85,724	88,930	111,180	104,355	74,030	96,625	121,724	144,778	1,312,162
2024F	148,154	127,155	115,910	92,046	85,450	88,645	110,824	104,021	73,793	96,316	121,335	144,314	1,307,962
After-Savings													
2023S	148,150	127,096	115,852	91,964	85,397	88,640	110,904	104,066	73,703	96,247	121,295	144,311	1,307,625
2024F	147,193	126,221	115,051	91,290	84,797	88,068	110,274	103,444	73,140	95,560	120,475	143,379	1,298,891

2.4 COMMERCIAL (MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Historical Actuals													
2013	65,750	60,623	56,214	57,036	69,494	61,665	67,834	73,941	72,704	67,185	66,229	69,533	788,208
2014	80,354	73,607	69,309	70,566	73,342	72,255	76,262	75,406	66,710	60,531	66,112	81,292	865,746
2015	80,156	72,259	68,665	64,591	71,392	74,678	72,149	71,980	68,558	62,811	67,227	78,701	853,168
2016	81,888	75,253	71,663	71,537	69,950	67,264	75,224	78,198	68,802	70,075	79,061	92,524	901,438
2017	87,580	76,292	77,390	69,008	70,517	72,425	82,456	81,640	72,344	73,698	77,035	80,003	920,385
2018	85,824	76,573	78,401	70,827	73,372	72,287	81,199	81,422	70,961	73,116	75,837	82,157	921,978
2019	85,718	80,999	80,956	69,682	72,347	72,907	78,731	80,774	73,021	75,361	78,350	85,041	933,887
2020	87,508	79,773	76,660	64,284	65,222	67,351	78,479	81,698	74,157	76,661	80,042	85,339	917,174
2021	87,315	79,792	80,058	71,855	73,925	80,219	85,512	69,286	96,034	76,263	80,232	90,890	971,380
2022	93,663	80,863	81,664	72,557	71,986	71,849	84,690	88,145	74,835	75,357	80,089	93,445	969,143
Before-Savings													
2023S	91,951	82,346	81,646	71,485	72,319	75,155	85,172	81,902	83,920	78,188	82,324	92,357	978,766
2024F	93,611	83,835	83,122	72,779	73,628	76,515	86,710	83,382	85,437	79,602	83,812	94,025	996,458
After-Savings													
2023S	90,995	81,393	80,699	70,545	71,387	74,230	84,248	80,976	82,989	77,249	81,377	91,404	967,494
2024F	91,705	81,937	81,239	70,914	71,779	74,679	84,880	81,551	83,599	77,757	81,960	92,169	974,168

2.5 WHOLESALE (MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Historical Normalized Actuals													
2013	103,661	88,423	80,309	42,225	37,653	34,630	44,414	42,889	38,531	44,175	51,637	66,656	675,204
2014	64,115	50,647	51,900	41,917	35,985	34,959	43,081	42,482	38,972	41,116	53,678	68,270	567,123
2015	65,841	58,564	51,584	41,088	41,147	36,029	45,222	43,897	37,441	42,668	51,945	65,059	580,485
2016	64,687	55,006	49,218	43,812	36,262	35,106	48,506	43,480	37,096	43,408	59,685	58,167	574,434
2017	61,637	51,026	51,573	40,753	35,692	35,965	47,044	49,971	39,411	42,639	56,771	61,621	574,101
2018	65,721	51,837	50,293	43,769	41,467	33,766	45,024	47,275	36,478	47,576	54,103	67,407	584,715
2019	61,944	48,097	50,091	42,390	39,513	36,881	47,393	44,924	37,351	44,052	49,804	63,534	565,972
2020	64,233	56,219	48,768	39,333	33,066	35,088	44,642	44,913	39,548	45,075	55,660	62,943	569,488
2021	63,822	56,888	51,016	42,771	35,118	32,874	43,009	44,315	36,150	44,201	57,331	58,330	565,827
2022	64,786	56,887	52,353	41,723	35,185	36,472	44,017	44,848	38,048	41,846	54,139	65,162	575,466
Before-Savings													
2023S	67,256	57,713	51,399	42,651	38,415	37,652	45,051	46,169	40,005	46,783	57,049	64,421	594,563
2024F	67,539	57,947	51,611	42,840	38,640	37,900	45,329	46,428	40,224	47,006	57,281	64,693	597,438
After-Savings													
2023S	66,907	57,368	51,064	42,331	38,109	37,357	44,759	45,873	39,699	46,463	56,714	64,076	590,719
2024F	66,842	57,258	50,944	42,202	38,032	37,313	44,750	45,843	39,618	46,374	56,622	64,014	589,812

2.6 INDUSTRIAL (MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Historical Actuals													
2013	19,966	30,774	23,744	24,489	31,517	33,006	29,815	29,726	31,598	32,105	32,500	33,084	352,325
2014	35,943	32,746	26,411	34,532	30,112	32,770	29,719	22,362	30,032	38,104	35,138	33,043	380,912
2015	32,138	33,574	32,797	31,186	36,574	26,261	27,971	34,078	32,395	29,853	27,852	34,997	379,676
2016	32,901	29,835	33,180	28,953	27,588	31,785	31,632	32,805	30,120	33,350	28,559	32,687	373,396
2017	33,109	30,227	32,593	30,117	27,928	31,621	29,477	29,518	28,665	28,831	30,770	29,734	362,590
2018	30,089	33,113	31,062	30,455	32,718	39,030	38,264	35,307	33,245	30,034	33,591	35,836	402,744
2019	40,014	40,563	41,563	37,886	39,198	40,876	38,967	41,784	39,929	49,045	45,695	39,390	494,911
2020	41,115	37,485	36,324	30,596	32,632	32,899	39,933	39,350	35,590	36,265	39,250	39,794	441,233
2021	39,629	38,120	44,021	42,125	34,088	34,473	33,956	35,536	42,333	41,558	42,792	43,684	472,315
2022	46,629	42,908	45,937	46,285	47,294	50,460	43,070	43,215	46,443	44,094	50,708	51,418	558,461
Before-Savings													
2023S	47,521	43,708	46,835	47,439	48,308	51,817	43,854	44,015	47,362	44,605	51,508	52,182	569,155
2024F	48,181	44,325	47,433	48,156	48,954	52,472	44,495	44,665	48,074	45,222	52,168	52,806	576,954
After-Savings													
2023S	46,915	43,102	46,233	46,841	47,721	51,233	43,279	43,436	46,785	44,009	50,910	51,595	562,059
2024F	46,977	43,131	46,259	46,998	47,826	51,360	43,409	43,582	47,004	44,123	51,075	51,743	563,488

2.7 LIGHTING (MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Historical Actuals													
2013	1,532	863	1,003	1,112	1,186	1,101	1,151	1,069	1,135	1,132	1,080	1,114	13,479
2014	1,282	1,273	1,251	1,310	1,327	1,331	1,329	1,374	1,257	1,255	1,260	1,382	15,633
2015	1,319	1,339	1,261	1,321	1,372	1,382	1,299	1,347	1,248	1,349	1,295	1,359	15,891
2016	1,245	1,363	1,341	1,362	1,361	1,347	1,404	1,381	1,294	1,191	1,251	1,388	15,930
2017	1,394	1,233	1,390	1,286	1,339	1,301	1,383	1,382	1,289	1,335	1,270	1,330	15,932
2018	1,385	1,178	1,291	1,307	1,198	1,118	1,068	998	988	952	848	894	13,225
2019	907	808	873	943	965	937	917	949	955	947	909	928	11,039
2020	929	892	955	900	914	874	932	949	878	907	863	852	10,846
2021	838	774	836	795	858	787	802	805	770	851	776	791	9,682
2022	820	724	772	760	790	729	784	762	767	800	766	788	9,262
Before-Savings													
2023S	804	743	797	763	796	743	783	782	751	796	748	756	9,262
2024F	804	743	797	763	796	743	783	782	751	796	748	756	9,262
After-Savings													
2023S	796	735	789	756	790	737	776	775	744	788	740	748	9,173
2024F	787	727	781	749	783	730	770	769	737	781	732	739	9,084

2.8 IRRIGATION (MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Historical Actuals													
2013	1,557	1,228	759	880	2,480	3,974	4,986	6,729	7,519	4,955	2,970	1,666	39,704
2014	633	549	932	2,227	4,512	7,013	8,146	6,822	4,501	2,578	1,267	847	40,025
2015	790	680	1,089	2,698	5,718	7,925	8,506	7,700	5,192	3,074	1,768	863	46,003
2016	822	834	1,341	3,172	4,888	5,748	7,561	7,778	4,724	2,694	1,739	765	42,065
2017	780	670	772	1,096	3,035	6,160	9,587	9,343	5,898	3,231	719	649	41,939
2018	700	662	761	1,419	4,521	6,271	8,461	8,024	4,348	2,465	681	666	38,979
2019	663	630	650	1,694	5,103	6,429	6,958	7,254	3,381	1,741	835	640	35,978
2020	708	660	662	1,987	3,535	3,752	7,936	8,743	5,588	2,317	709	662	37,260
2021	674	606	641	2,272	5,957	7,621	10,099	7,568	4,242	2,508	701	751	43,640
2022	760	655	718	1,400	3,452	4,028	7,631	8,660	5,441	3,049	965	804	37,563
Before-Savings													
2023S	699	628	660	1,848	4,227	5,029	8,381	8,154	4,987	2,571	776	724	38,684
2024F	699	628	660	1,848	4,227	5,029	8,381	8,154	4,987	2,571	776	724	38,684
After-Savings													
2023S	698	627	659	1,846	4,222	5,018	8,364	8,134	4,970	2,561	771	722	38,592
2024F	698	626	657	1,844	4,217	5,007	8,346	8,113	4,954	2,552	767	720	38,500

2.9 SYSTEM PEAK (MW)

System Peak (MW)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Winter	Summer
Historical Normalized Actuals														
2013	720	631	549	493	515	442	600	565	523	502	598	698	698	600
2014	651	580	562	469	403	482	620	605	412	467	572	645	693	620
2015	693	679	568	488	501	523	611	587	437	514	669	631	685	611
2016	685	683	569	540	490	582	587	593	443	480	613	724	755	593
2017	755	673	595	510	597	505	600	605	561	515	594	648	714	605
2018	714	648	583	516	602	533	630	631	429	459	609	659	682	631
2019	678	682	651	514	568	502	626	639	538	562	622	701	732	639
2020	732	680	609	500	482	515	666	665	551	549	631	667	731	666
2021	711	731	555	495	488	653	597	635	486	509	628	675	685	653
2022	685	676	572	490	432	615	681	689	629	480	673	734	734	689
Before-Savings														
2023S	723	701	615	519	494	607	682	676	527	537	655	742	788	700
2024F	728	705	619	522	497	611	687	681	531	541	660	747	793	705
After-Savings														
2023S	719	696	611	515	490	603	678	672	523	533	651	738	783	696
2024F	720	696	611	514	490	603	679	673	523	533	652	739	785	697

Note: The peaks shown in the table above are seasonal peaks. The seasonal winter peak is based on November and December of the current year and January and February of the following year. The seasonal summer peak is based on June, July and August of the current year and includes the June 2021 Heat Dome.

3. CUSTOMER FORECAST

3.1 CUSTOMERS

Customer Count	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023S	2024F
Residential	111,862	113,431	114,166	115,772	117,748	120,291	122,465	124,966	126,678	129,131	131,323	133,291
Commercial	13,662	14,363	14,976	15,073	15,398	15,678	15,956	16,165	16,594	16,773	16,930	17,290
Wholesale	6	6	6	6	6	6	6	6	6	6	6	6
Industrial	47	49	50	50	50	52	51	43	42	42	42	42
Lighting	1,644	1,620	1,590	1,559	1,511	1,482	1,467	1,443	1,407	1,380	1,357	1,330
Irrigation	1,097	1,103	1,095	1,090	1,080	1,078	1,082	1,091	1,103	1,103	1,103	1,103
Total Direct	128,318	130,572	131,883	133,550	135,793	138,587	141,027	143,714	145,830	148,435	150,761	153,063

3.2 CUSTOMER ADDITIONS

Customer Additions	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023S	2024F
Residential	(433)	1,569	735	1,606	1,976	2,543	2,174	2,501	1,712	2,453	2,192	1,969
Commercial	489	701	613	97	325	280	278	209	429	179	157	360
Wholesale	(1)	-	-	-	-	-	-	-	-	-	-	-
Industrial	(4)	2	1	-	-	2	(1)	(8)	(1)	-	-	-
Lighting	(95)	(24)	(30)	(31)	(48)	(29)	(15)	(24)	(36)	(27)	(23)	(26)
Irrigation	6	6	(8)	(5)	(10)	(2)	4	9	12	-	-	-
Total Direct	(38)	2,254	1,311	1,667	2,243	2,794	2,440	2,687	2,116	2,605	2,326	2,302

4. NORMALIZED AFTER-SAVINGS USE PER CUSTOMER (UPC)

MWh/Customer	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023S	2024F
Residential	12.48	11.51	11.41	11.27	11.31	11.03	10.43	10.89	10.57	10.32	10.04	9.82

5. LOAD

5.1 AFTER-SAVINGS LOAD

Energy (GWh)	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023S	2024F
Residential	1,352.9	1,296.5	1,298.1	1,295.6	1,320.5	1,312.6	1,266.1	1,346.8	1,330.3	1,320.4	1,307.6	1,298.9
Commercial	788.2	865.7	853.2	901.4	920.4	922.0	933.9	917.2	971.4	969.1	967.5	974.2
Wholesale	675.2	567.1	580.5	574.4	574.1	584.7	566.0	569.5	565.8	575.5	590.7	589.8
Industrial	352.3	380.9	379.7	373.4	362.6	402.7	494.9	441.2	472.3	558.5	562.1	563.5
Lighting	13.5	15.6	15.9	15.9	15.9	13.2	11.0	10.8	9.7	9.3	9.2	9.1
Irrigation	39.7	40.0	46.0	42.1	41.9	39.0	36.0	37.3	43.6	37.6	38.6	38.5
Net	3,221.9	3,165.9	3,173.4	3,202.8	3,235.4	3,274.2	3,307.9	3,322.8	3,393.2	3,470.3	3,475.7	3,473.9
Losses & Company Use	278.1	270.1	272.4	273.8	282.3	285.1	286.9	287.9	299.7	314.6	298.9	298.7
Gross	3,500.0	3,436.0	3,445.8	3,476.6	3,517.7	3,559.4	3,594.8	3,610.8	3,692.8	3,784.8	3,774.5	3,772.7
System Peak (MW)												
Winter Peak	698.1	692.6	685.0	754.7	713.6	682.2	732.4	730.8	684.8	734.3	783.4	785.0
Summer Peak	600.4	619.5	611.0	593.0	604.8	630.9	639.4	666.2	652.9	689.1	696.2	697.3

5.2 NORMALIZED AFTER-SAVINGS WHOLESALE LOAD

Wholesale (GWh)	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023S	2024F
BCH Lardeau	6.3	6.3	6.5	5.9	8.4	7.8	7.1	6.1	5.9	5.0	6.6	6.5
BCH Kingsgate	4.9	4.6	4.8	4.9	4.6	4.7	4.6	5.0	4.1	4.0	4.6	4.6
City of Grand Forks	41.1	39.5	40.7	40.5	38.7	45.8	36.9	37.5	36.3	37.0	37.5	37.5
City of Nelson	82.7	80.9	83.0	79.6	86.1	88.0	83.8	82.0	85.6	86.0	84.5	83.2
City of Penticton	348.4	341.9	348.4	345.2	338.0	340.0	338.4	340.3	337.0	347.0	357.9	357.9
District of Summerland	97.9	94.0	97.1	98.2	98.2	98.5	95.1	98.5	96.9	96.0	99.7	100.1
City of Kelowna	93.9	-	-	-	-	-	-	-	-	-	-	-
Total	675.2	567.1	580.5	574.4	574.1	584.7	566.0	569.5	565.8	575.0	590.7	589.8

5.3 DSM (GWH) WITHOUT LOSSES

Energy (GWh)	2018	2019	2020	2021	2022	2023S	2024F
Demand Side Management	(31.4)	(25.8)	(26.3)	(30.0)	(35.9)	(26.9)	(52.8)

6. VARIANCES TO FORECAST

6.1 CUSTOMER COUNT VARIANCE

Customer Count	2017	2018	2019	2020	2021	2022
Actual						
Residential	117,748	120,291	122,465	124,966	126,678	129,131
Commercial	15,398	15,678	15,956	16,165	16,594	16,773
Wholesale	6	6	6	6	6	6
Industrial	50	52	51	43	42	42
Lighting	1,511	1,482	1,467	1,443	1,407	1,380
Irrigation	1,080	1,078	1,082	1,091	1,103	1,103
Total	135,793	138,587	141,027	143,714	145,830	148,435
Forecast						
Residential	116,031	117,774	120,405	124,076	124,603	128,941
Commercial	15,813	16,122	16,405	16,220	16,579	16,975
Wholesale	6	6	6	6	6	6
Industrial	50	50	51	57	59	43
Lighting	1,590	1,559	1,511	1,425	1,393	1,406
Irrigation	1,095	1,090	1,080	1,082	1,082	1,091
Total	134,585	136,602	139,459	142,865	143,721	148,462
Variance (customers)						
Residential	1,717	2,517	2,060	890	2,075	190
Commercial	(415)	(444)	(449)	(55)	15	(202)
Wholesale	0	0	0	0	0	0
Industrial	0	2	0	(14)	(17)	(1)
Lighting	(79)	(77)	(44)	18	14	(26)
Irrigation	(15)	(12)	2	9	21	12
Total	1,208	1,986	1,569	849	2,109	(27)
Variance (%)						
Residential	1.5%	2.1%	1.7%	0.7%	1.6%	0.1%
Commercial	-2.7%	-2.8%	-2.8%	-0.3%	0.1%	-1.2%
Wholesale	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Industrial	0.0%	3.8%	0.0%	-32.6%	-40.5%	-2.4%
Lighting	-5.2%	-5.2%	-3.0%	1.3%	1.0%	-1.9%
Irrigation	-1.4%	-1.1%	0.2%	0.8%	1.9%	1.1%
Total	0.9%	1.4%	1.1%	0.6%	1.4%	0.0%

6.2 LOAD VARIANCE, NORMALIZED/HISTORIC ACTUAL TO FORECAST[1]

Energy (GWh)	2017	2018	2019	2020	2021	2022
Historic						
Residential	1,320.5	1,312.6	1,266.1	1,346.8	1,330.3	1,320.4
Commercial	920.4	922.0	933.9	917.2	971.4	969.1
Wholesale	574.1	584.7	566.0	569.5	565.8	575.5
Industrial	362.6	402.7	494.9	441.2	472.3	558.5
Lighting	15.9	13.2	11.0	10.8	9.7	9.3
Irrigation	41.9	39.0	36.0	37.3	43.6	37.6
Net	3,235.4	3,274.2	3,307.9	3,322.8	3,393.2	3,470.3
Gross	3,517.7	3,559.4	3,594.8	3,610.8	3,692.8	3,784.8
Forecast						
Residential	1,353.0	1,280.0	1,349.3	1,325.6	1,255.4	1,283.2
Commercial	879.4	912.0	935.2	901.7	952.3	945.5
Wholesale	587.3	586.0	594.0	567.5	583.5	559.5
Industrial	407.0	379.0	385.0	453.0	536.7	470.4
Lighting	14.4	15.0	13.0	10.6	9.9	10.3
Irrigation	40.3	41.0	42.0	35.3	35.8	37.1
Net	3,282.2	3,213.0	3,318.5	3,293.7	3,373.7	3,306.0
Gross	3,559.0	3,485.0	3,602.0	3,602.0	3,664.0	3,591.0
Variance (GWh)						
Residential	(32.5)	32.6	(83.2)	21.3	74.9	37.1
Commercial	41.0	10.0	(1.3)	15.5	19.1	23.6
Wholesale	(13.2)	(1.3)	(28.0)	2.0	(17.7)	16.0
Industrial	(44.4)	23.7	109.9	(11.8)	(64.3)	88.1
Lighting	1.5	(1.8)	(2.0)	0.2	(0.3)	(1.0)
Irrigation	1.7	(2.0)	(6.0)	2.0	7.8	0.5
Net	(46.8)	61.2	(10.6)	29.2	19.5	164.3
Gross	(41.3)	74.4	(7.2)	8.8	28.9	193.9
Variance (%)						
Residential	-2.5%	2.5%	-6.6%	1.6%	5.6%	2.8%
Commercial	4.4%	1.1%	-0.1%	1.7%	2.0%	2.4%
Wholesale	-2.3%	-0.2%	-5.0%	0.4%	-3.1%	2.8%
Industrial	-12.3%	5.9%	22.2%	-2.7%	-13.6%	15.8%
Lighting	9.4%	-13.4%	-17.8%	2.1%	-2.8%	-10.7%
Irrigation	3.9%	-5.2%	-16.7%	5.3%	17.9%	1.3%
Net	-1.4%	1.9%	-0.3%	0.9%	0.6%	4.7%
Gross	-1.2%	2.1%	-0.2%	0.2%	0.8%	5.1%

[1] Residential and Wholesale historic loads shown are normalized loads. All other rate classes show historic actual loads.

6.3 NORMALIZED AFTER-SAVINGS ANNUAL PERCENT GROWTH

Energy (GWh)	2017	2018	2019	2020	2021	2022	2023S	2024F
Residential	1,320.5	1,312.6	1,266.1	1,346.8	1,330.3	1,320.4	1,307.6	1,298.9
Commercial	920.4	922.0	933.9	917.2	971.4	969.1	967.5	974.2
Wholesale	574.1	584.7	566.0	569.5	565.8	575.5	590.7	589.8
Industrial	362.6	402.7	494.9	441.2	472.3	558.5	562.1	563.5
Lighting	15.9	13.2	11.0	10.8	9.7	9.3	9.2	9.1
Irrigation	41.9	39.0	36.0	37.3	43.6	37.6	38.6	38.5
Net	3,235.4	3,274.2	3,307.9	3,322.8	3,393.2	3,470.3	3,475.7	3,473.9
Losses & Company Use	282.3	285.1	286.9	287.9	299.7	314.6	298.9	298.7
Gross	3,517.7	3,559.4	3,594.8	3,610.8	3,692.8	3,784.8	3,774.5	3,772.7
System Peak								
Winter Peak (MW)	713.6	682.2	732.4	730.8	684.8	734.3	783.4	785.0
Summer Peak (MW)	604.8	630.9	639.4	666.2	652.9	689.1	696.2	697.3

Growth Year over Year	2017	2018	2019	2020	2021	2022	2023S	2024F
Residential	1.9%	-0.6%	-3.5%	6.4%	-1.2%	-0.7%	-1.0%	-0.7%
Commercial	2.1%	0.2%	1.3%	-1.8%	5.9%	-0.2%	-0.2%	0.7%
Wholesale	-0.1%	1.8%	-3.2%	0.6%	-0.6%	1.7%	2.7%	-0.2%
Industrial	-2.9%	11.1%	22.9%	-10.8%	7.0%	18.2%	0.6%	0.3%
Lighting	0.0%	-17.0%	-16.5%	-1.7%	-10.7%	-4.3%	-1.0%	-1.0%
Irrigation	-0.3%	-7.1%	-7.7%	3.6%	17.1%	-13.9%	2.7%	-0.2%
Net	1.0%	1.2%	1.0%	0.5%	2.1%	2.3%	0.2%	0.0%
Losses & Company Use	3.1%	1.0%	0.6%	0.4%	4.1%	5.0%	-5.0%	0.0%
Gross	1.2%	1.2%	1.0%	0.4%	2.3%	2.5%	-0.3%	0.0%
System Peak								
Winter Peak (MW)	-5.4%	-4.4%	7.4%	-0.2%	-6.3%	7.2%	6.7%	0.2%
Summer Peak (MW)	2.0%	4.3%	1.4%	4.2%	-2.0%	5.5%	1.0%	0.1%

Customer Count	2017	2018	2019	2020	2021	2022	2023S	2024F
Residential	117,748	120,291	122,465	124,966	126,678	129,131	131,323	133,291
Commercial	15,398	15,678	15,956	16,165	16,594	16,773	16,930	17,290
Wholesale	6	6	6	6	6	6	6	6
Industrial	50	52	51	43	42	42	42	42
Lighting	1,511	1,482	1,467	1,443	1,407	1,380	1,103	1,103
Irrigation	1,080	1,078	1,082	1,091	1,103	1,103	1,357	1,330
Total Direct	135,793	138,587	141,027	143,714	145,830	148,435	150,761	153,063

Growth Year over Year	2017	2018	2019	2020	2021	2022	2023S	2024F
Residential	1.7%	2.2%	1.8%	2.0%	1.4%	1.9%	1.7%	1.5%
Commercial	2.2%	1.8%	1.8%	1.3%	2.7%	1.1%	0.9%	2.1%
Wholesale	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Industrial	0.0%	4.0%	-1.9%	-15.7%	-2.3%	0.0%	0.0%	0.0%
Lighting	-3.1%	-1.9%	-1.0%	-1.6%	-2.5%	-1.9%	-20.1%	0.0%
Irrigation	-0.9%	-0.2%	0.4%	0.8%	1.1%	0.0%	23.0%	-1.9%
Total Direct	1.7%	2.1%	1.8%	1.9%	1.5%	1.8%	1.6%	1.5%

6.4 RESIDENTIAL UPC, NORMALIZED ACTUAL TO FORECAST

Residential UPC (MWh)	2020	2021	2022
After- Savings Normalized Actual UPC	10.89	10.57	10.32
Forecast	10.75	10.10	10.04
Variance	0.13	0.48	0.29
Variance (%)	1.2%	4.5%	2.8%

6.5 WINTER PEAK, ACTUAL TO FORECAST

Winter Peak (MW)	2020	2021	2022
Actual Peak	725.0	777.0	835.0
Forecast	737.0	748.0	716.5
Variance	(12.0)	29.0	118.5
Variance (%)	-2%	4%	17%

Note: The peaks reflected in this table are the actual seasonal peaks are not normalized.

6.6 SYSTEM LOAD FACTOR

The following table shows annual after-savings gross load, peak load and load factor. The annual load factor is calculated as annual load ÷ peak hourly load x number of hours in a year (8,760).

Year	Energy (MWh)	Peak (MW)	Load Factor
2017	3,517,718	714	0.56
2018	3,559,367	682	0.60
2019	3,594,813	732	0.56
2020	3,610,765	731	0.56
2021	3,692,835	684	0.62
2022	3,784,830	733	0.59
2023S	3,774,539	783	0.55
2024F	3,772,679	785	0.55

Note: The peaks in this table represent annual peaks meaning they happened in the calendar year and are not the seasonal peaks.

Appendix A3

Load Forecast Methods

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1. LOAD FORECAST METHODS

This appendix describes FBC's load forecast methods on which the forecast in Section 3 of the Application is based.

In the figures provided in this appendix, the following three time frames are shown:

- Actual Years: Actual years are those for which actual data exists for the full calendar year[1]. For the 2024 Annual Review the latest calendar year for which full actual data exists is the 2022 calendar year.
- Seed Year: The Seed Year is the year prior to the first forecast year. The Seed Year is forecast based on the latest years of actual data available, and will be different than the original forecast for that year in the previous filing. For example, for this Application the Seed Year is 2023 (2023S) and the Seed Year forecast is based on the latest actual years, including 2022. As such, the 2023 Seed Year forecast in this Application will differ from the 2023 Forecast presented in the Annual Review for 2023 Rates, for which 2022 actual data was not available.
- Forecast Year(s): This is the year or years for which the forecast is being developed. This can be one year (in the case of the Annual Review) or a range of two or more years depending on the filing. In this Application, 2024 is the Forecast Year (2024F).

1.1 *WEATHER NORMALIZATION*

Electricity consumption is impacted by weather, particularly by temperature. For example, load requirements in an extremely cold winter month can be significantly higher than requirements in normal weather conditions in the same month, due to additional heating loads. As the load forecast is made under an assumption of normal weather, it is necessary to remove those extreme weather effects from the historical data. This is the first step in forecasting.

Statistical tests were made to check whether the residential, wholesale, commercial and irrigation loads were sensitive to temperature due to heating and cooling demands and whether the irrigation load was sensitive to the amount of precipitation[2]. The results from the regression for these four rate classes are shown below. The regressions result in high R^2 values for all seasons for the residential and wholesale load classes; therefore these classes are normalized. The commercial class shows a low R^2 value for all seasons and the irrigation class for the winter, summer and fall seasons; therefore, these classes were not normalized.

[1] FBC's load forecast is developed using only full years of historical data. FBC requires the full year of load data in order to validate it, including the review of and potential adjustments to unbilled energy. For this reason partial year data is not used in forecasting.
[2] Industrial and lighting loads are typically insensitive to the weather.

Table A3-1: Residential Regression Table

Residential	Winter	Spring	Summer	Fall
Intercept	35,802	71,302	76,725	70,811
Slope HDD	180	108	-	93
Slope CDD	-	-	250	-
Adjusted R^2	0.77	0.75	0.83	0.78

Table A3-2: Wholesale Regression Table

Wholesale	Winter	Spring	Summer	Fall
Intercept	63,808	60,024	33,068	34,997
Slope HDD	60	49	-	32
Slope CDD	-	-	103	-
Adjusted R^2	0.91	0.95	0.85	0.79

Table A3-3: Commercial Regression Table

Commercial	Winter	Spring	Summer	Fall
Intercept	50,957	49,648	69,253	71,660
Slope HDD	25	18	-	(2)
Slope CDD	-	-	78	-
Adjusted R^2	0.31	0.28	0.36	(0.05)

Table A3-4: Irrigation Regression Table

Irrigation	Winter	Spring	Summer	Fall
Intercept	1,382	5,363	5,017	5,846
Slope HDD	(1)	(12)	-	(11)
Slope CDD	-	-	24	-
Adjusted R^2	0.01	0.78	0.53	0.52

Steps for weather (temperature) normalization are as follows:

1. Calculate monthly Heating Degree Days (HDD)[3] and Cooling Degree Days (CDD)[4] for the Penticton weather station.
2. Calculate 10-year HDD and CDD averages for each month of the year. These are used as the parameters of normal weather.
3. For each of the residential and wholesale classes, regress load on HDD or CDD on a seasonal basis. Four seasons were defined: winter (November to February), spring

[3] Heating degree-days for a given day are the number of Celsius degrees that the mean temperature is below 18 Celsius degrees.
[4] Cooling degree-days for a given day are the number of Celsius degrees that the mean temperature is above 18 Celsius degrees.

(March to May), summer (June to August) and fall (September to October). Thus all monthly load and degree day data for each season is used and four separate regressions are calculated for each class. The City of Kelowna (CoK) Event variables were included in the regressions to recognize the integration of the CoK in 2013 into the FBC direct customer base.

4. To normalize a month, e.g. February 2022:

   (a) obtain the month's HDD (or CDD) information from Environment Canada;

   (b) calculate the deviation from the 10-year average (2013-2022) HDD (CDD) as found in Step 2;

   (c) apply the regression slope obtained in Step 3 to this deviation to come up with a normalization adder; and

   (d) add the normalization adder to the month's load (residential or wholesale).

The general equation to normalize load requirements in month t is shown below.

$$Normalized\ Load_t = Load_t - HDD\ Slope_t \times (HDD_t - Normal\ HDD_t)$$

$$where\ HDD\ is\ Heating\ Degree\ Days\ and\ t = Spring, Fall\ and\ Winter$$

And

$$Normalized\ Load_t = Load_t - CDD\ Slope_t \times (CDD_t - Normal\ CDD_t)$$

$$where\ CDD\ is\ Cooling\ Degree\ Days\ and\ t = Summer$$

1.2 *LOAD FORECAST*

FBC forecasts energy requirements by customer class based on weather normalized historical loads. These are referred to as the "before-savings[5]" loads. DSM savings that are incremental to those embedded in historical loads (up to and including 2022) are also forecast for each customer class and subtracted from the before-savings loads to arrive at the "after-savings" loads. This section discusses the before-savings forecast load requirements for each of FBC's load classes.

1.2.1 Residential

The formula to forecast the expected before-savings residential load in year *t* is:

$$Before\ Savings\ Load_t = UPC_t \times Average\ Customer\ Count_t$$

where UPC (use per customer in MWh per customer per year) is before-savings.

[5] The term "before-savings" is used in the remainder of this section and refers to "before incremental savings after 2022".

The before-savings UPC was based on a 10-year historic trend of annual UPC values from 2013 to 2022.

Table A3-5: Results of UPC Trend Analysis

Regression	UPC
Start Year	2013
End Year	2022
R^2	0.825
Adjusted R^2	0.803
df	9
Intercept	395
Slope UPC	-0.19

Next, average customer count in year *t* is calculated as:

$$Average\ Customer\ Count_t = \frac{(Year\ End\ Count_t + Year\ End\ Count_{t-1})}{2}$$

The year-end customer count was based on the least squares regression model below.

$$Year\ End\ Customer\ Count_t = b_0 + b_1 \times Population_t$$

$Population_t$ is the population data supplied by BC Stats for the Company's direct service area.

Table A3-6: Results of Residential Customer Count Regression

Regression	Residential
Start Year	2017
End Year	2022
R^2	0.996
Adjusted R^2	0.995
df	5
Intercept	(3,342)
Slope Population	0.46

The residential class represented 38.0 percent of the net load in 2022.

1.2.2 Commercial

The expected before-savings commercial load in year *t* is forecast based on the provincial GDP supplied by the CBOC. The relationship was estimated from the following equation.

$$Before\ Savings\ Load_t = (b_0 + b_1 \times GDP_t + b_2 \times CoK\ Event_t) + FBC\ EV\ DC\ Fast\ Chargers$$

The CoK_t is a binary variable for the City of Kelowna integration event in 2013. Coefficients b0, b1 and b2 are obtained from an ordinary least squares (OLS) regression analysis on the 2008 to 2022 data. The FBC EV DCFCs are Electric Vehicle Direct Current Fast Chargers serviced by FBC which are added to the forecast. The commercial class represented 27.9 percent of the net load in 2022.

Table A3-7: Results of Commercial Regression

Regression	Commercial
Start Year	2008
End Year	2022
R^2	0.987
Adjusted R^2	0.985
df	14
Intercept	186,072
Slope GDP	2
Slope CoK Event	136,787

1.2.3 Wholesale

The Company forecasts the wholesale load based on load surveys from the wholesale customers. For this forecast, FBC received surveys from all the wholesale customers. FBC then summed the wholesale customers' forecasts to calculate the before-savings wholesale load forecast. This approach recognizes that in the near to medium term, the wholesale customers themselves are best able to forecast their load growth based on their knowledge of their customer mix, load behaviors, development projects with associated load requirements, etc. The wholesale class represented 16.6 percent of the net load in 2022.

1.2.4 Industrial

The before-savings industrial load is the sum of forecasts supplied by those individual customers who responded to the load survey and, for customers who did not respond, escalation of the customer's load in the preceding year by the CBOC forecast GDP growth rates for the industrial sector the customer is in. 76 percent of FBC's industrial customers responded to the surveys, accounting for 91 percent of 2022 load.

FBC assumes no new industrial customers in the current forecast unless there is a confirmed commitment from an industrial customer. FBC works with key account managers to identify new customers and existing customers with expansion plans that have commited contracts that are being added to the system. The key account managers work with the new customers directly and relay the load requirements to the forecasting group. The industrial class represented 16.1 percent of the net load in 2022.

1.2.5 Irrigation

The before-savings irrigation load forecast uses a five-year average so that the extreme weather events such as those that occurred in 2022 are included in the forecast but do not overly influence it. The irrigation class represented 1.1 percent of the net load in 2022.

1.2.6 Lighting

The before-savings lighting load uses the 2022 actuals due to the variability in the load primarily due to streetlight LED replacement programs which reduced the loads from 2018 to 2022. The lighting class represented 0.3 percent of the net load in 2022.

1.2.7 Demand Side Mangment (DSM) Savings

FBC forecasts load reductions resulting from its DSM programs.

The forecast of DSM savings is consistent with the Company's approved 2019-2022 DSM Plan. DSM measures are grouped into applicable programs that are then added to produce the three primary sector (residential, commercial & industrial) annual plan savings targets. Finally, the annual sector targets beginning with the Seed Year are converted into a cumulative time series, and disaggregated into the customer rate classes and commensurate system loss reductions.

1.3 *PEAK DEMAND FORECAST*

The peak demand forecast is produced by taking the 10-year average (2013-2022) of historical peak data. The historical peak data is escalated by the gross load growth rate before it is averaged to account for the growth of demand on the FBC system. Self-generating customers are removed from the historical load data since the underlying trends that impact other loads do not apply. Seasonal peaks were used for both the winter and the summer. The 12 monthly peaks, as well as the seasonal peaks, were then escalated by the annual load growth rates in the forecast period to produce forecast monthly peaks. The winter peak and the summer peak are assumed to replace monthly peaks in December and July, respectively.

The after DSM peak forecast was calculated by subtracting DSM capacity savings forecast from the before DSM peak forecast for each month in each year.

Appendix B
PRIOR YEAR DIRECTIVES

No.	Decision Page No.	Directive No.	Reference	Description / Details	Status	Section in this Application
G-166-20 – FBC MULTI-YEAR RATE PLAN FOR 2020 THROUGH 2024						
1.	75	24	General Flow-through Deferral Account	The Panel directs [FBC] to provide a detailed analysis of the individual forecast variances recorded in the Flow-through deferral account in each Annual Review.	Ongoing during the MRP term	Section 12.4.2.1
2.	87	32	Efficiency Carry-Over Mechanism	Therefore, the Panel determines the following process for the handling of an ECM application: 1. An ECM can be applied for at any time in the last three years of the MRPs, either in advance or following the action or initiative being undertaken. 2. For proposed activities where identifiable savings are expected to extend beyond the term of the MRP, FortisBC is to file an ECM proposal describing the initiative, its timing, costs and benefits and savings. 3. Parties will have the opportunity to review and comment on the proposal and the BCUC will determine whether to approve the ECM proposal (an Approved ECM Initiative). 4. FortisBC must submit details of continued savings annually under an Approved ECM Initiative as part of the Annual Review process. The net savings will be shared equally between ratepayers and the Utilities will carry forward past the end of the MRP for a maximum period of three years.	No approved ECM initiatives to report on	n/a
3.	99	35	SAIDI and SAIFI major events	The Panel also directs FBC to include a discussion of major events relevant to the SAIDI and SAIFI results in future Annual Review materials.	Ongoing during the MRP term	Section 13
4.	99-100		SQI Informational Indicators	In addition to the SQIs, the Panel approves the following informational indicators for the Utilities: • Customer Satisfaction Index (measures overall customer satisfaction) – FEI and FBC. • Average Speed of Answer (average number of seconds to answer emergency and non-emergency calls) – FEI and FBC. • Generator Forced Outage Rate (percent of time a generating unit is removed from service due to component failure or other events) – FBC only. • Interconnection Utilization (percent of time that an interconnection point was available and providing electrical service to wholesale customers) – FBC only. The Utilities are directed to report on these informational indicators along with the SQIs as part of the Annual Review process.	Ongoing during the MRP term	Section 13

No.	Decision Page No.	Directive No.	Reference	Description / Details	Status	Section in this Application
5.	118	42	System Operations, Integrity and Security Expenditures	The Panel directs FBC to provide the following information related to System Operations, Integrity and Security expenditures in its future revenue requirements applications over the term of the Proposed MRPs: 1. A breakdown and explanation of both annual and cumulative variances between forecast/actual and formula O&M related to System Operations, Integrity and Security expenditures, which quantify the variances attributable to the following areas: • Tree management; • Generation dam safety; • Network operations apprentice program; • Cyber security; • Data analytics; and • Any other significant factors or miscellaneous items. 2. A description of how FBC is prioritizing its System Operations, Integrity and Security expenditures.	Ongoing during the MRP term	Section 6.2.1
G-374-21 – FBC ANNUAL REVIEW FOR 2022 RATES						
6.	32	8	EV Charging Updates	The Panel directs FBC to include in future Annual Review filings an update on its EV DCFC charging stations' costs and revenues for the previous fiscal year along with a forecast of costs and revenues for the test period.	Ongoing	Sections 3.6, 5.8, 6.3.4 and 7.2.2.1
G-14-23 – FBC PRINCETON BRIDGE STREET PROPERTIES DISPOSITION						
7.	n/a	4	Princeton Office Disposition Deferral Account	FBC is directed to provide details of the final balance in the Princeton Office Disposition deferral account in the FBC Annual Review for 2024 Rates.	Complete	Section 7.6.2.1

Appendix C
DRAFT ORDER

bcuc
British Columbia
Utilities Commission

Suite 410, 900 Howe Street
Vancouver, BC Canada V6Z 2N3
bcuc.com

P: 604.660.4700
TF: 1.800.663.1385
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ORDER NUMBER
G-xx-xx

IN THE MATTER OF
the *Utilities Commission Act*, RSBC 1996, Chapter 473

and

FortisBC Inc.
Annual Review for 2024 Rates

BEFORE:
[Panel Chair]
Commissioner
Commissioner

on Date

ORDER

WHEREAS:

A. On June 22, 2020, the British Columbia Utilities Commission (BCUC) issued its Decision and Order G-165-20 for FortisBC Energy Inc. and Order G-166-20 for FortisBC Inc. (FBC) approving a Multi-Year Rate Plan for 2020 through 2024 (MRP Decision). In accordance with the MRP Decision, FBC is to conduct an annual review (Annual Review) process to set rates for each year;

B. By letter dated June 28, 2023, FBC proposed a regulatory timetable for the Annual Review of its 2024 rates;

C. By Order G-191-23, the BCUC established a regulatory timetable for the Annual Review for FBC's 2024 rates, which included FBC filing its Annual Review materials, the deadline for intervener registration, one round of information requests, a workshop, FBC's response to undertakings at the workshop, and written final and reply arguments;

D. On August 4, 2023, FBC submitted its materials for the Annual Review for 2024 Rates Application (Application). In the Application, FBC requests a 4.83 percent rate increase over the 2023 rates, effective January 1, 2024, among other things; and

E. The BCUC has reviewed the Application, evidence and arguments filed in the proceeding and makes the following determinations.

NOW THEREFORE pursuant to sections 59 to 61 of the *Utilities Commission Act*, for the reasons stated in the decision issued concurrently with this order, the BCUC orders as follows:

1. FBC is approved to recover the 2024 revenue requirement and resultant rate change on a permanent basis, effective January 1, 2024, as filed in the Application and subject to any adjustments identified by FBC during

the regulatory process and from any directives or determinations made by the BCUC in its decision on the Application.

2. FBC is approved to establish the following rate base deferral accounts:

    a. 2025 Multi-year Rate Plan (MRP) Application deferral account, with the amortization period to be determined in a future proceeding;

    b. 2024 Mandatory Reliability Standards (MRS) Audit deferral account, with an amortization period of three years, commencing January 1, 2024;

    c. PST Rebate on Select Machinery and Equipment deferral account, with an amortization period of one year, commencing January 1, 2024;

    d. BC Cost of Living Credit deferral account, with an amortization period of one year, commencing January 1, 2024; and

    e. Climate Change Operational Adaptation (CCOA) Plan deferral account, with an amortization period of four years, commencing January 1, 2024.

3. FBC is directed to file as a compliance filing, the finalized financial schedules and updated tariff pages within 10 days from the date of the issuance of this order.

DATED at the City of Vancouver, in the Province of British Columbia, this (XX) day of (Month Year).

BY ORDER

(X. X. last name)
Commissioner

Northland Utilities
A NI and ATCO Company

March 7, 2023

Northwest Territories Public Utilities Board
203 – 62 Woodland Drive
Box 4211
Hay River, NT X0E 1G1

To: Mr. Gordon Van Tighem
Board Chairman

RE: Northland Utilities (NWT) Limited (Northland)
2023 Amended General Rate Application (GRA)

By letter dated January 31, 2023, the Northwest Territories Public Utilities Board (Board) accepted Northland Utilities (NWT) Limited's (Northland) proposal to file its Amended 2023 General Rate Application (Application) and its Hay River Franchise Property Disposition Application by March 7, 2023.[1]

In addition to the requested approval of the Hay River Franchise Property Disposition in a separate Application, the only other significant update included in this Application, as compared to the original 2023 GRA submitted on September 22, 2022, is Section 14 (Supplemental Information) which includes a scenario whereby the Town of Hay River remains in Northland's Revenue Requirement. This information is for illustration purposes and has been prepared to aid the Board in reviewing and comparing rate impacts when the Town of Hay River is included in Revenue Requirement. There are no other substantive changes in this Application as compared to the original 2023 GRA filed on September 22, 2022.

As outlined in Section 1, the Application is primarily driven by the discontinuation of the Hay River Franchise Agreement and the disposition of the Hay River franchise assets to the Town of Hay River. The Application is for a single Test Year in 2023 to allow the Board to review the public interest considerations associated with the discontinuation of

[1] Board Letter dated January 31, 2023.

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service and disposition of assets in Hay River and the resulting rates for Northland's remaining customers.

This Application includes:

- Determination of the 2023 Revenue Requirement for remaining Northland customers in Sections 1, 2-15;
- Northland's request for a Hay River Transition Deferral in Section 1B; and
- Business Cases for Capital Additions in Section 16, including two Business Cases that require Project Permits.

As set out in the proposed schedule below, a final decision is not expected until later in 2023. Therefore, Northland requests interim approval for the following:

- Rate changes for the remaining Northland customers as outlined in Sections 1, 2 to 15; and
- Interim use of the proposed Hay River Transition Deferral requested in Section 1B.
- New Transmission rate requested in Section 1B.

Interim approval will create administrative efficiencies, reduce complexities with the Hay River Disposition and limit future true-ups. A Decision for Interim Refundable Rates approval must be received prior to April 21, 2023, to ensure rates are incorporated into the billing system.

Northland proposes the following written process:

Process Step	Written Process
File Application	March 7, 2023
Notice of Application	March 13, 2023
Intervener Registration	March 20, 2023
IRs to Northland from Board & Interveners	March 27, 2023
IR Responses from Northland	April 17, 2023
Interim Refundable Rate Approval	April 21, 2023

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Process Step	Written Process
Intervener Evidence, if necessary	April 24, 2023
IRs to Interveners on Evidence	May 1, 2023
IR Responses from Interveners	May 15, 2023
Rebuttal Evidence, if necessary	May 25, 2023
Argument	June 6, 2023
Reply Argument	June 19, 2023

Due to the narrow scope of the Application, Northland's relatively small size, and in an effort to promote Regulatory Efficiency, Northland proposes to limit the number of intervener Information Requests to a maximum of 50, including sub-parts.[2]

Subject to the Board's approval and in accordance with Section 22(5) of the *Public Utilities Act (PUA)* and Section 13.1 of Rules of Practice and Procedure, Northland is prepared to commence the public notification process with respect to the Application. Advertisements will be placed in News/North, The Hub, and any other news outlet Northland deems appropriate. Northland will provide copies of each advertisement to the Board.

If you have any questions with respect to this Application, please contact me at Elizabeth.Rogers@atco.com.

Yours truly,

Beth Rogers
Director, Regulatory

[2] In an effort to reduce regulatory burden measures such as this have been adopted by the Alberta Utilities Commission, most recent in Proceeding 27062, Exhibit 27062-X0273.

Northland Utilities
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Northland Utilities
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Section 1 – Introduction

Summary

1. This Section outlines:

- Approvals requested from the NWT Public Utilities Board (Board);
- Background on Northland Utilities (NWT) Limited (Northland);
- Hay River Disposition and 2023 Revenue Requirement;
- Overview of the Pandemic Impact;
- Applied-For Revenue Requirement;
- Rate Rider Adjustment;
- Deferral Accounts;
- Key Assumptions;
- Return on Equity (ROE) and Capital Structure;
- Common Costs Treatment; and
- Revenue Requirement Analysis including Town of Hay River.

Approvals Requested from the Board

2. Northland seeks the following approvals from the Board:

(1) Approval for a deferral account to address the timing of transfer of Hay River assets effective January 1, 2023 (included in Section 1B);

(2) Approval for a separate long-term deferral account for costs associated with the extended Taltson shut down (included in Section 1B);

(3) Approval of Northland's revenue requirement for the 2023 Test Year (one-year Test Period);

(4) Approval of a final Rate Adjustment Rider (Rider R), a new Transmission Rate, and updates to Riders A & F (included in Sections 1B & 15);

(5) Interim Refundable Rates approval by April 21, 2023, to be implemented May 1, 2023 (as sought in the cover letter);

(6) Approval for continuation of existing deferral accounts listed below;

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(7) Approval of the ROE risk premium described in Section 7;

(8) Project permits for two projects in 2024 consistent with Section 54 of the *Public Utilities Act (PUA)* described in Section 16; and

(9) Such further and other relief as the Board may determine is appropriate.

About Northland

3. Northland is a wholly-owned subsidiary of Northland Utilities Enterprises Ltd. (NUE). NUE is 50% owned by ATCO Electric Ltd. through Norven Holdings Inc., and 50% owned by Denendeh Investments Incorporated.

4. Northland started operations in Hay River in 1951 with three small diesel engines located on Vale Island. The Company served 96 customers plus an additional 14 streetlights. In 1972, Enterprise and Fort Providence were added to Northland's service area. Sambaa K'e became part of the Northland's service area in 1986 and Wekweeti in 1987.

5. In 1988, Northland completed a $3.5 million Transmission Line from Pine Point to Hay River after Cominco completed mining operations. Hay River continues to be supplied with renewable energy from the Taltson Hydro System.

6. Prior to the Hay River disposition request herein, Northland provided electrical service to approximately 2,700 customers in the communities of Sambaa K'e, Wekweeti, Kakisa, Enterprise, Dory Point, Hay River, Fort Providence and the K'atl'odeeche First Nation Reserve. Northland operates five diesel power plants, in addition to receiving energy from the Taltson Hydro System.

7. On March 24, 2016, the Town of Hay River (the Town) notified Northland that it would not be renewing the Franchise Agreement and that it intended to exercise its right to purchase the Franchise Assets. As a result of the discontinuation of the Franchise Agreement and subsequent sale of the Franchise Assets (collectively,

the Hay River Disposition), Northland's 2023 forecasts exclude the assets, customers and costs related to Hay River.

Hay River Disposition and 2023 Revenue Requirement

8. Herein, Northland is seeking approval of a 2023 revenue requirement which has been forecast to reflect the Hay River Disposition effective January 1, 2023. As a result of the Hay River Disposition, Northland requires new rates for the remaining customers. Due to uncertainty regarding the specific timing of transfer of the Franchise Assets to the Town, Northland is also requesting approval of a deferral account related to the Hay River Disposition. The deferral would capture any surpluses or shortfalls for the time Northland operates the Franchise Assets beyond January 1, 2023. This proposed deferral account is further discussed in Section 1B.

Impact of the Pandemic

9. In 2020, the COVID-19 pandemic caused lockdowns, work from home orders, travel and border restrictions, and general economic uncertainty. As an essential service, Northland experienced a number of changes from historical trends with respect to energy usage patterns for residential and commercial customers as work from home mandates were imposed; requirements to reassign staff and shift work; and costs related to supply chain issues and personal protective equipment.

10. As pandemic restrictions lift, the economy is expected to return to pre-pandemic levels in 2023 and, given worldwide events (like supply chain constraints), Northland has seen upward pressure on material and labour prices. This is reflected in higher-than-normal inflation assumptions used for 2023 (which are discussed further below).

11. The impact of COVID-19 was considered in the development of the 2023 proposed sales forecast, O&M, and capital expenditure forecasts where appropriate.

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Applied-For Revenue Requirement

12. The associated tariffs and revenue requirement applied for are detailed in Schedules 2.0, 2.1, 3.0 and 3.1 and are summarized in Table 1-1, below.

Table 1-1 – Applied-For Revenue Requirement ($000s)

	2023		
	Total Company	**Hydro Zone**	**Thermal Zone**
Northland Revenue Requirement (before Transmission Revenue and Fuel Prices)	5,357	1,893	3,464
Increase Over Existing Rates	1,420	1,128	293
Revenue Requirement Increase (Before Transmission Revenue and Fuel Prices) (%)	**36%**	**147%**	**9%**
Revenue Requirement Increase (Decrease) Net of Transmission Revenues and Fuel Prices	(354)	17	(371)
Revenue Requirement Increase Net of Increase in Fuel Prices (%)	**-9%**	**2%**	**-12%**

Rate Adjustment Rider (Rider R)

13. As explained in Section 15, Northland is requesting interim approval to update the Rate Adjustment Rider (Rider R) for implementation on May 1, 2023, to begin collecting the applied-for Revenue Requirement shortfall on a refundable basis.

14. To implement Rider R on May 1, 2023, Board approval is required on or before April 21, 2023.

15. Any adjustments required to Rider R following a Board Decision will be made in a subsequent Compliance Filing.

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Deferral Accounts

16. The previously accepted criteria for establishing a deferral account have not changed from Northland's 2011-2013 Phase I GRA. The criteria are:

    (a) not under the control of the company and not reasonably forecastable; or

    (b) an error in forecasting could produce a loss or gain of substantial magnitude.

17. Northland is requesting approval to use the following Deferral Accounts during the Test Year, refer to Table 1-2.

Table 1-2 – Deferral Accounts

Deferral Account	Section	Previously Approved
Timing of Hay River Asset Disposition	Section 1B	New Request
Backup Generation for Taltson Shutdown	Section 1B	New Request
Purchase Power Flow Through	Section 3	9-2014
Diesel Fuel Price Variance	Section 4	9-2014
Hay River Diesel Generation Variance	Section 4	9-2014
Defined Benefit Pension Plan	Section 5	9-2014
Income Tax Rate Deferral Account	Section 8	9-2014

18. In addition to the deferral accounts listed above, Northland is requesting approval to continue its deferral account used to record amounts associated with any Board Decisions, or changes to statutory or legislative provisions, that result in changes to the rules or parameters under which Northland operates, including such areas as the billing system, collection practices or the frequency of meter reading, and that impact Northland's 2023 Revenues and/or Revenue Requirements. For clarity, no such recorded amounts would be approved by the Board as part of this Application. Rather, the balance(s) would be brought forward by Northland for consideration in a future application to the Board.

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Key Assumptions

	2023
Labour Inflation – In Scope	3.5%
Labour Inflation – Out of Scope	4.0%
Other Inflation	6.0%
Vacancy Rate	0.0%

19. For the 2023 Test Year, in-scope (subject to a collective agreement) and out-of-scope (not subject to a collective agreement) labour have been escalated by 3.5 percent and 4.0 percent, respectively. This escalation rate reflects Northland's forecast given the current labour market for specialized skills in the North of 60 and inflation pressures. To ensure Northland is able to attract and retain talent in a challenging and evolving labour market, Northland has aligned labour inflation assumptions to trends realized in Alberta, where a large portion of employees have historically been recruited from. The last collective agreement in place at Northland was for the period January 1, 2019 to December 31, 2021. A final agreement for 2022 and beyond has not been reached.

20. For non-labour costs, the forecast provided by the Bank of Canada (BoC) Monetary Policy Report dated July 2022,[1] has been applied to the Test Year. Events such as the Russian invasion of Ukraine, continued supply chain challenges, and changes to inflation expectations, have all increased the inflation outlook. While high inflation in Canada is largely the result of international factors, domestic demand pressures are becoming more prominent, and price pressures have broadened. This has resulted in high inflation, which is expected to persist over the next one to two years. Given the foregoing, Northland has utilized the sustained higher inflation forecast as it is seen to be reasonable for the 2023 Test Year, as rising inflation over the past couple of years has led to expectations of continued high inflation among firms surveyed by the BoC. It is thus doubtful that

[1] https://www.bankofcanada.ca/wp-content/uploads/2022/07/mpr-2022-07-13.pdf.

the past two years of high inflation being experienced in Northwest Territories and Canada will reverse any time soon.

21. As described in Section 5, Northland has not forecast a vacancy rate, as the complement forecast is the minimum number of FTEs possible to operate the system safely and reliably, recognizing that vacancies or leave time must be filled with contractors or external resources going forward.

22. Northland is not forecasting any new long-term debt to be issued within this Test Year.

Return on Equity (ROE) and Capital Structure

23. As outlined in Section 7, consistent with previously approved methodologies, Northland requests setting the ROE for the Test Year at the percentage determined on a generic basis for all Alberta Utilities for 2023, as determined by the Alberta Utilities Commission (AUC) in the 2023 Alberta Generic Cost of Capital Proceeding (2023 GCOC Proceeding),[2] plus a risk premium of 1.25 percent to reflect the added business risk due to the Hay River Disposition.

24. Northland is not requesting a change to the five percent adder previously approved for the common equity ratio.

Common Costs Treatment

25. In its letter dated January 31, 2023, the Board requested that Northland address the determination and treatment of common costs following the Hay River Disposition.[3] In order to determine the impacts on common costs, please refer to

[2] Proceeding ID 27084.
[3] Board Letter dated January 31, 2023.

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Section 5 Operations and Maintenance (O&M) expenses and associated explanations related to common costs, post Hay River Disposition.

Revenue Requirement Including the Town of Hay River

26. For purposes of aiding the Board with respect to reviewing the impact on Revenue Requirement and Rates related to the Hay River Disposition, Northland has prepared Revenue Requirement calculations for the 2023 Test Year that, in addition to the Diesel communities, include the Town of Hay River. This Revenue Requirement calculation essentially represents a 'Status Quo' scenario that includes all of Northland's communities, including the Town of Hay River. Please refer to Section 14 Supplemental Information for the Revenue Requirement calculations that include the Town of Hay River, as well as discussion respecting the methodologies associated with the determination and treatment of common costs.

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Section 1B – Implications of the Hay River Disposition

Background

1. While approval of the Hay River Disposition is being sought in a separate Application, the consequence of the proposed transaction significantly affects all aspects of this Application. This Section outlines various considerations that are inextricable from the disposition, particularly:

   i. Expected timing of the disposition and transaction;
   ii. Backup Generation for Taltson Shutdown;
   iii. Hay River Transition Deferral Account;
   iv. Costs related to the disposition of the Franchise Assets; and
   v. New Rates.

Expected Timing and Sales Transaction

2. The transaction for the purchase and sale of the Franchise Assets has not yet closed. A full transition of the Franchise Assets to Hay River is expected to occur later in 2023. While the exact transfer date is unknown, the following table estimates the transaction value as of January 1, 2023. Upon closing of the transaction and transfer of the Franchise Assets to the Town, Northland will notify the Board of the final actual amounts.

Table 1B-1 – Estimated Transaction Dollar Value as of January 1, 2023 ($000s)

Item to be Transferred	Estimated Dollar Value as of January 1, 2023
Net Book Value (net of contributions and negative salvage)	6,656
Deferral Accounts	(367)
Impact on utility Books	**6,289**
Costs Related to the Hay River Disposition	1,421
Premium Approved (1)	2,215
Total Proceeds (2)	**9,925**

(1) Per arbitration – should have no impact to utility customers.
(2) Excludes amounts approved by the arbitrator related to data acquisition.

Disposition of Net Book Value (net of Contributions)

3. Below are the Franchise Assets that will be transferred.

Table 1B-2 - Transferred Assets
($000s)

Asset	Estimate Net Book Value
Distribution (incl. Substation)	4,998
Generation	714
General	944
Net Book Value (net of Contributions)	**6,656**

Disposition of Deferral Accounts

4. As a result of the Hay River Disposition, Northland will true-up deferral account balances to apportion those amounts for which Hay River customers are responsible.

Table 1B-3 – Disposition of Deferral Accounts
($000s)

Deferral Account	Estimated Dollar to be Transferred December 31, 2022
Purchase Power Flow Through	(41)
Diesel Variance	438
Pension Deferral	(54)
Reserve Balances	(587)
Franchise Tax Balances	11
Net Metering Deferral Account	33
Rider H (Cost of Capital Refund)	(167)
Hay River Transition Deferral	0
Backup Generation -Taltson Shutdown	0
Total Deferral Amount Transferred	**(367)**

5. Northland notes that these deferrals will be trued-up at the time of transition as the table reflects estimates. Throughout the Application, Northland is proposing to

continue using previously approved deferrals. The Hay River transition deferral and rate are discussed further in section below.

Backup Generation for Taltson Shutdown

6. In its letter to the Board dated December 15, 2022, Northland indicated that it was notified by NTPC that the Taltson Hydro Overhaul would run from approximately April 2023 to November 2023.[1] With generation costs estimated to be approximately $1 million per month and the timing of the Hay River Disposition expected to occur later into 2023, Northland is seeking approval to record the costs related to providing back-up generation during the shutdown in a separate long-term deferral account, 'Backup Generation for Taltson Shutdown' that is amortized over the expected life of NTPC's generation assets. Accordingly, Northland proposes to amortize the 'Backup Generation for Taltson Shutdown' cost on a 50-year basis, matching NTPC's approved IOWA curve 50-S2[2] for Account 333 Hydro Plan-Water, Wheels, Turbines and Generators.

7. Northland notes that attempting to include these costs in Northland's approved Hay River Diesel Generation deferral account (as outlined in Section 4) and recovering the costs over a one or two year timeframe would result in rate shock and inappropriately burden current ratepayers with costs that have intergenerational benefits. Further, Northland submits this treatment is consistent with the Board's practices as well as utility regulators in other jurisdictions which approved capital treatment during a prolonged shut down.

8. Expenditures expected to be included in the proposed deferral account include fuel, labor and any other supplies required to operate Hay River diesel generators

[1] Northland Letter to the Board dated December 15, 2022.
[2] From NTPC 2022-23 GRA Appendix A, 2020 Depreciation Study, pages 3-5.

during the shutdown. If approved, the deferral will be trued-up and the entire balance will be transferred over to the Town of Hay River at the time of transition.

Hay River Transition Deferral

9. Northland understands the transition date may change depending on how this proceeding unfolds. Therefore, Northland hereby requests a deferral account to track any surpluses or shortfalls associated with Northland providing service to Hay River beyond January 1, 2023.

10. The proposed deferral account will function as follows:

    i. Hay River customers will continue to be served on existing rates, whereas Northland's remaining customers (i.e., non-Hay River Customers) will have rates adjusted in accordance with Board approvals.

    ii. Actual costs incurred to operate the Hay River system – including, but not limited to, operating and administrative costs, financing costs, depreciation and tax – will be collected in this deferral beginning January 1, 2023.

    iii. Any shortfall or surplus resulting from continued service by Northland to Hay River customers beyond January 1, 2023, under existing rates will be recorded in a deferral account and will be invoiced or refunded to the Town or the utility operator at the time of the transition, in accordance with Board approvals. Other existing deferral accounts will be trued up at this time, as well.

    iv. Any costs or efficiencies realized from shared costs as a result of Northland continuing to serve Hay River in 2023 that may impact Northland's remaining customers will be trued-up in a Compliance Filing.

Costs Related to the Hay River Disposition

11. In addition to the Net Book Value transfer amount and Deferral accounts discussed above, additional prudently incurred utility costs result from the Hay River Disposition, as shown in Table 1B-4 below.

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Table 1B-4 – Estimated Transfer of Costs to the Town of Hay River ($000s)

Cost Incurred	Estimated Outstanding Amounts
Long Term Debt Break Fees [3]	476
Employee Severance Costs	275
Costs Related to the Segregation of Assets	150
Legal & Consultant Fees	520
Total Costs Transferred	**1,421**

12. In its letter dated January 31, 2023, the Board requested that Northland address costs related to the Hay River Disposition in a separate Application.[4] Accordingly, please refer to Northland's concurrent Hay River Disposition Application for further details regarding the appropriateness of these Disposition Costs and Northland's requested approval in a separate Application.

13. This Application excludes these costs related to the Hay River Franchise area from the 2023 Test Year, as these costs are being addressed in Northland's Disposition Application. Accordingly, Northland respectfully requests that, the Board approve the Disposition Costs as shown in Table 1B-4, which are further supported in Northland's Hay River Disposition Application, and that these costs be included with the Hay River Transition Deferral amounts and be invoiced directly to the Town or utility operator at the time of transition. In the alternative, if the Board determines that it is not appropriate for these costs to be directly invoiced to the Town or the utility operator, Northland requests approval to include these prudently incurred utility costs in its 2023 GRA such that they can be recovered from Northland's remaining customers. While Northland's position is that customers within the Town should be responsible for the Disposition Costs, if the Board is of a different view, Northland submits that the Board should allow Northland to

[3] Please refer to Northland's concurrent Hay River Disposition proceeding regarding update for LT Debt Break fees.
[4] Board Letter dated January 31, 2023.

recover these costs from its remaining customers given that they were reasonably and prudently incurred utility costs.

New Transmission Rate

14. As a result of the Hay River Disposition, Northland's transmission assets will be segregated from its customers. Electricity will first flow to Hay River over Northland's transmission line, and then wheeled over the Hay River distribution system to provide wholesale service back to Northland at a metering point where the electricity leaves the Hay River distribution system.

15. Northland is allocating the transmission costs to the Town of Hay River using the energy allocator, in accordance with Decision 1-2016 and the Guideline 4 from the GNWT Electricity Rate Policy Guidelines. Northland notes this allocator significantly limits the expected rate impacts for the remaining Northland customers, which are highly sensitive to deviations in revenue requirement due to remaining billing determinants. For example, absent any transmission revenue offset, the remaining customers in the Hydro Zone would see an approximate 147 percent rate increase or, in other words, every $100,000 in costs allocated to the remaining Hydro Zone ratepayers will result in a rate increase of approximately 13 percent. Any changes to the allocation of costs or approved revenue requirements will have significant implications on the resulting rates for Northland's remaining customers and should be a consideration in Northland's concurrent Hay River Disposition proceeding when assessing whether the disposition of the Hay River franchise meets the public interest test, particularly any harm to existing customers.

16. Please refer to Schedule 3.2 for the transmission cost calculations and Attachment 1 for the price schedule related to transmission services, effective immediately following the Hay River Disposition.

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Conclusion

17. While approval of the Hay River Disposition forms part of a separate Application, the implications of the Hay River Disposition and timing thereof impact this Application. Accordingly, Northland requests approval of the following:

(i) Disposition of approved deferrals as set out in Table 1B-3 above, including the costs associated with Backup Generation of the Taltson Shutdown.

(ii) The Hay River Transition Deferral to true-up any surpluses or shortfall associated with Northland providing service to Hay River beyond January 1, 2023, including the recovery of approved of Disposition costs as outlined in Table 1B-4.

(iii) A new Transmission rate to recover transmission costs related to the Town of Hay River.

Effective: _____
Supersedes: _____

NORTHLAND UTILITIES (NWT) LIMITED
An ***ATCO*** Company

HYDRO RATE ZONE
TRANSMISSION RATE SCHEDULE

Available

- In the Northwest Territories for the operator of the distribution system in the Town of Hay River.

Applicable

- For electricity delivered over the transmission line from Pine Point to the Town of Hay River.

Rates

- Fixed Charge of:
  $92,599 per month
- Energy Charge of
  $0.00 per kWh
- Demand Charge of
  $0.00 per kW
- The minimum monthly charge is the Fixed Charge

Options and Riders

Price Adjustments – the following price adjustments (Riders) may apply:

- Diesel Fuel Cost Adjustment (Rider A)
- Temporary Refund/Surcharge (Rider E)
- Purchase Power Cost Adjustment (Rider F)
- Cost Recovery/Refund (Rider H)
- Interim Refundable Rate (Rider K)
- Rate Adjustment Rider (Rider R)
- Franchise Tax

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Section 2 – Sales and Revenue

Sales

Overview

1. As discussed in Section 1, the 2023 forecast excludes the sales and revenues for Hay River, effective January 1, 2023. Table 2.1 below provides the breakdown of sales by customer class. The sharp drop in 2023 sales is due to the Hay River Disposition. Sales and Revenue for remaining customers are forecast to be flat in 2023.

Table 2.1 – Northland Energy Sales by Customer Class (MWh)

	Actual			Forecast	
Customer Class	**2019**	**2020**	**2021**	**2022**	**2023[1]**
Residential	11,478	12,193	12,188	11,790	2,890
Commercial	21,392	20,339	20,441	20,457	3,240
Streetlights	552	548	546	547	135
Sentinel Lights	190	199	198	194	50
Total Company	**33,612**	**33,280**	**33,373**	**32,988**	**6,315**

[1] Excludes Town of Hay River

2. The COVID-19 global pandemic impacted Residential and Commercial Usage Per Customer (UPC) in 2020 and 2021. During this period, Residential UPC increased as more people were working from home and Commercial UPC decreased as businesses were impacted by COVID-19 restrictions as well as the decrease in employees working in offices. As pandemic restrictions ease, policies and procedures are beginning to normalize, such that the 2023 forecast anticipates UPCs to return to pre-pandemic levels for both residential and commercial customers.

3. Northland's detailed energy sales by customer class, along with corresponding revenue for 2019-2021 (Actual) and 2022-2023 (Forecast), are provided in Schedule 2.1.

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Background

4. In 2020 and 2021, the economy of the NWT was disrupted by the pandemic. GDP fell by 11 percent in 2020 and modestly recovered by 6.3 percent in 2021.[1] Little population growth has occurred over the past several years in NWT, with the population growing at an annual average rate of 0.3 percent from 2016-2021.[2] With pandemic related restrictions recently starting to ease, 2022 UPC is beginning to return to pre-pandemic levels.

5. In 2021, Northland's service territory covered the Town of Hay River, Enterprise, K'atl'odeeche First Nation Reserve, Fort Providence, Wekweeti, Sambaa K'e, Kakisa, and Dory Point. As Table 2.2 below indicates, sales to residential customers in the Hydro Rate Zone communities (the Town of Hay River, Enterprise, and K'atl'odeeche First Nation Reserve) accounted for 84 percent of Northland's total residential sales in 2021, with Fort Providence accounting for 11 percent and the remaining communities accounting for five percent. Likewise, commercial sales in the Hydro Rate Zone communities accounted for 90 percent of Northland's total commercial sales in 2021, with sales to Fort Providence accounting for seven percent and the remaining communities accounting for three percent.

6. In terms of the distribution of energy sales by rate class, residential customers accounted for 37 percent of Northland's total energy sales in 2021, while sales to commercial customers and lighting accounted for 61 percent and two percent, respectively. Table 2.2 below, provides the 2021 annual average customer numbers and the associated energy sales by community for residential and commercial classes.

[1] Gross Domestic Product Northwest Territories, 2021 Preliminary. From: https://www.statsnwt.ca/economy/gdp/May2022_GDP.pdf, accessed July 11, 2022.
[2] Northwest Territories Population, April 2022. From: https://www.statsnwt.ca/population/population-estimates/PopEst_Apr2022.pdf, accessed July 11, 2022.

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Table 2.2 - 2021 Northland Residential and Commercial Customers and Sales by Community

		Residential				Commercial			
Community	Rate Zone	Customers[1]	Share (%)	Energy (MWh)	Share (%)	Customers[1]	Share (%)	Energy (MWh)	Share (%)
Hay River	Hydro	1,468	73	9,133	75	439	69	17,104	84
Ft. Providence	Thermal	284	14	1,399	11	79	12	1,388	7
K'atl'odeeche	Hydro	89	4	721	6	29	4	821	4
Enterprise	Hydro	59	3	387	3	43	7	430	2
Wekweeti	Thermal	43	2	251	2	19	3	376	2
Sambaa K'e	Thermal	40	2	200	2	17	3	202	1
Dory Point/Kakisa	Thermal	21	1	97	1	15	2	120	1
Total		**2,004**	**100**	**12,188**	**100**	**640**	**100**	**20,441**	**100**

1) Annual Averages

Forecast Process

7. Similar to the past methodology, the sales forecasts for 2022 and 2023 are prepared by customer class. The 2022 forecast includes actual data for January to June.

(i) Residential

8. The residential sales forecast has two key inputs: the net customer additions and the UPC. The energy sales forecast is calculated by multiplying the forecast number of customers by the UPC forecast.

9. The number of customer additions is based on information collected from the municipal/community officials, local developers in each community, and historical customer additions.

10. Residential energy consumption in normal circumstances is typically very similar for most families. In general, temperature can play a role in residential energy consumption, although other factors such as the size of the dwelling, the size of household, and economic factors also influence residential energy consumption. The 2022 residential sales forecast includes six months of actual data. Energy for the remaining months of 2022 and 2023 is forecast by multiplying the monthly customer forecast by the corresponding forecast of UPC. The Residential UPC forecast is calculated using the community's three-year average UPC from the pre-pandemic period of 2017 to 2019. K'atl'odeeche and Dory Point/Kakisa

forecast UPC is the same as in 2019. The historical UPC is weather-normalized for communities where temperature is found to have an impact on usage.

(ii) Commercial

11. The forecast of commercial customer additions is derived using information collected from Northland's customers, the communities, and local developers, as well as historical customer additions. The energy sales forecast is calculated by multiplying the forecast number of customers by the UPC forecast.

12. The 2022 commercial sales forecast includes six months of actual data. Energy for the remaining months in 2022 and 2023 for each community is forecast by multiplying the monthly customer forecast by the UPC forecast. The Commercial UPC forecast is calculated using the community's three-year average UPC from the pre-pandemic period of 2017 to 2019. Dory Point/Kakisa and Sambaa K'e forecast UPC is the same as in 2019. In K'atl'odeeche, customer additions since 2019 were forecast separately.

13. Section 2, Attachment 1 provides the data and the detailed calculations of the residential and commercial UPC forecast by community.

(iii) Street and Sentinel Lighting

14. The energy forecast for street and sentinel lighting is obtained by multiplying the forecast number of customers by the average usage per light. Average usage is calculated based on wattage characteristics and light types. The customer additions forecast is based on discussions with developers in the community and consultation with community officials as well as historical customer additions.

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2023 Forecast

(i) Residential

15. Energy sales to residential customers are expected to decrease by 76 percent and customer numbers are expected to decrease by 73 percent in 2023, largely due to the discontinuation of the Franchise Agreement.

16. In the remaining communities, energy sales are expected to mildly increase compared to pre-pandemic levels.

Table 2.3 – Residential Energy Sales (MWh) by Area

	2019	2020	2021	2022	2023
		Actual		Forecast	
Hay River	8,671	9,147	9,133	8,825	-
Remaining Hydro	979	1,076	1,108	1,033	1,013
Thermal	1,828	1,971	1,946	1,932	1,877
Total	**11,478**	**12,193**	**12,188**	**11,790**	**2,890**

(ii) Commercial

17. Energy sales to commercial customers are expected to decrease by 84 percent and customer numbers are expected to decrease by 68 percent in 2023 mainly due to the discontinuation of the Franchise Agreement.

18. In the remaining Hydro communities, energy sales are expected to mildly increase compared to pre-pandemic levels, whereas energy sales in the Thermal communities are expected to mildly decrease compared to pre-pandemic levels.

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Table 2.4 – Commercial Energy Sales (MWh) by Area

	2019	2020	2021	2022	2023
		Actual		Forecast	
Hay River	18,122	17,175	17,104	17,172	-
Remaining Hydro	1,231	1,181	1,251	1,261	1,274
Thermal	2,039	1,983	2,085	2,024	1,966
Total	**21,392**	**20,339**	**20,441**	**20,457**	**3,240**

(iii) Street and Sentinel Lighting

19. Energy sales to lighting customers are forecast to decrease 74 percent in 2023 due to the discontinuation of the Franchise Agreement. In the remaining communities, lighting customers and sales are expected to remain flat.

Revenue

Base Rate Revenue

20. To forecast revenue on existing rates, the current rates in place effective August 1, 2022, were applied to the sales forecast. Details of revenue by rate class are provided in Schedule 2.1.

Transmission Revenue

21. As discussed in Section 1B, Northland is seeking approval to recover revenue for transmission expenses from the Town.

Other Revenue

22. Northland's other revenues have been included with retail sales revenues as part of the revenue requirement. These amounts are detailed in Schedule 10.0.

23. Services to outside party revenues have been forecast based on a three-year historic average increase. Penalty revenue, reconnect revenue, and other revenues are based on three-year historic averages. Joint use revenues are based on forecast pole attachments and attachment rates.

Northland Utilities (NWT) Limited (Northland)
2023 Amended General Rate Application (GRA)
Variables Definition

NWT

Definition of the variables used in the regression equation

Name	Definition
MHDD	Monthly Heating Degree Days
MCCNT	Monthly Commercial Customer Count
MCENCNS	Monthly Commercial Energy Consumption
MCUPC	Monthly Commercial Average Use Per Customer (UF
MRCNT	Monthly Residential Customer Count
MRENCNS	Monthly Residential Energy Consumption
MRUPC	Monthly Residential Average Use Per Customer (UP(
N_MHDD	"Normal" (20-yr Average) HDD

Northland Utilities (NWT) Limited (Northland)
2023 Amended General Rate Application (GRA)
Enterprise - Data

Enterprise

			Residential						Commercial			
Year	Month	monthly	MRCNT	MRENCNS (MWh)	MRUPC (kWh)	MHDD (Hay River)	Normalized UPC (kWh)	Annual Normalized UPC (kWh)	MCCNT	MCENCNS (MWh)	MCUPC (kWh)	Annual UPC (kWh)
2005	1	Jan-05	35	29.6	847.1	1259.5	835.2		36	53	1,479	
2005	2	Feb-05	35	28.7	819.8	1034.4	827.1		36	62	1,723	
2005	3	Mar-05	35	21.0	599.7	949.1	613.1		36	51	1,416	
2005	4	Apr-05	36	20.2	560.6	542.4	586.4		36	52	1,447	
2005	5	May-05	36	17.0	472.8	407.1	466.4		39	40	1,038	
2005	6	Jun-05	36	13.9	386.4	208.8	374.4		39	35	907	
2005	7	Jul-05	36	12.8	354.7	86.0	349.1		39	42	1,079	
2005	8	Aug-05	36	14.5	403.1	143.2	395.4		39	45	1,144	
2005	9	Sep-05	38	14.1	371.5	308.0	360.9		42	44	1,043	
2005	10	Oct-05	37	14.6	394.1	473.7	405.7		35	36	1,035	
2005	11	Nov-05	37	17.0	460.4	767.1	484.5		35	43	1,233	
2005	12	Dec-05	37	21.7	587.5	866.3	652.9	**6,351**	35	38	1,072	**14,615**
2006	1	Jan-06	37	23.1	623.3	1164.8	634.9		35	53	1,523	
2006	2	Feb-06	37	21.5	582.2	927.4	615.9		35	42	1,202	
2006	3	Mar-06	37	21.5	582.1	904.4	606.5		35	46	1,304	
2006	4	Apr-06	37	19.3	521.7	497.2	558.7		37	41	1,120	
2006	5	May-06	37	15.3	412.6	312.1	429.7		39	31	798	
2006	6	Jun-06	38	15.0	396.0	98.3	411.3		39	32	814	
2006	7	Jul-06	37	16.3	441.8	85.2	436.5		40	36	891	
2006	8	Aug-06	37	12.9	348.8	90.1	354.2		40	29	737	
2006	9	Sep-06	37	12.7	343.4	203.1	358.8		40	29	728	
2006	10	Oct-06	38	14.3	377.1	524.3	376.1		43	38	872	
2006	11	Nov-06	38	19.3	508.3	1042.4	464.3		37	42	1,134	
2006	12	Dec-06	39	23.7	607.5	925.2	658.3	**5,905**	37	47	1,269	**12,394**
2007	1	Jan-07	39	23.4	601.3	1108.2	626.8		37	48	1,286	
2007	2	Feb-07	39	22.7	583.2	1168.2	557.3		37	44	1,193	
2007	3	Mar-07	39	27.8	711.9	1099.9	687.9		37	44	1,192	
2007	4	Apr-07	37	19.7	533.3	559.6	554.9		37	39	1,066	
2007	5	May-07	40	16.2	404.4	368.0	407.7		37	31	832	
2007	6	Jun-07	39	15.6	399.5	161.2	399.2		40	47	1,180	
2007	7	Jul-07	38	17.2	452.3	37.8	458.7		40	46	1,154	
2007	8	Aug-07	38	12.4	326.3	187.3	307.7		40	25	617	
2007	9	Sep-07	38	14.5	380.8	365.5	356.0		41	32	769	
2007	10	Oct-07	40	15.4	385.3	489.4	392.9		39	28	729	
2007	11	Nov-07	41	21.0	511.7	849.8	515.3		37	35	945	
2007	12	Dec-07	42	20.5	489.1	1188.0	474.8	**5,739**	41	38	921	**11,885**
2008	1	Jan-08	40	26.9	673.6	1215.4	672.6		42	51	1,215	
2008	2	Feb-08	40	26.8	670.7	1201.8	636.4		38	47	1,227	
2008	3	Mar-08	42	25.5	608.1	1090.8	586.3		43	45	1,038	
2008	4	Apr-08	41	19.7	481.2	689.4	470.6		40	44	1,092	
2008	5	May-08	41	18.0	439.1	358.0	444.9		40	37	926	
2008	6	Jun-08	43	15.8	367.4	154.9	368.7		39	34	876	
2008	7	Jul-08	44	13.3	301.8	35.2	308.8		40	31	765	
2008	8	Aug-08	43	16.2	376.6	102.8	378.9		41	33	799	
2008	9	Sep-08	45	15.6	346.2	315.4	333.7		40	36	896	
2008	10	Oct-08	43	15.0	349.0	477.7	359.6		41	29	718	
2008	11	Nov-08	41	20.3	496.0	777.7	517.5		28	30	1,060	
2008	12	Dec-08	44	21.2	480.8	1280.6	443.6	**5,522**	36	41	1,145	**11,758**
2009	1	Jan-09	44	30.4	690.8	1237.6	684.4		34	48	1,408	
2009	2	Feb-09	44	21.4	486.6	1084.9	481.3		34	39	1,161	
2009	3	Mar-09	44	24.4	554.5	1116.3	526.5		36	48	1,340	
2009	4	Apr-09	44	20.0	455.2	623.2	461.0		36	42	1,172	
2009	5	May-09	44	17.3	392.2	489.9	365.3		41	29	718	
2009	6	Jun-09	42	18.1	430.7	192.7	422.6		42	33	794	
2009	7	Jul-09	43	15.5	359.9	101.3	350.6		42	33	781	
2009	8	Aug-09	43	14.4	334.4	87.7	340.4		42	33	775	
2009	9	Sep-09	43	16.5	384.5	176.8	406.4		42	36	851	
2009	10	Oct-09	43	16.9	392.4	559.7	382.7		42	35	837	
2009	11	Nov-09	43	17.1	397.4	824.5	407.3		37	23	611	
2009	12	Dec-09	43	22.0	511.0	1163.4	502.8	**5,331**	37	34	923	**11,372**
2010	1	Jan-10	43	27.5	640.0	1229.1	635.6		37	40	1,073	
2010	2	Feb-10	43	23.0	535.1	900.2	575.6		37	36	978	
2010	3	Mar-10	43	19.7	458.4	718.9	528.7		37	35	957	
2010	4	Apr-10	43	18.8	436.1	491.0	474.7		37	31	844	
2010	5	May-10	43	16.7	388.5	401.5	383.5		37	22	592	
2010	6	Jun-10	43	18.0	417.8	120.0	427.7		41	30	723	
2010	7	Jul-10	43	15.0	349.6	45.3	354.2		42	27	652	
2010	8	Aug-10	45	17.2	381.2	109.4	381.9		42	32	768	
2010	9	Sep-10	46	16.7	362.8	293.5	355.8		42	31	728	
2010	10	Oct-10	46	17.8	387.9	463.7	402.0		42	30	709	
2010	11	Nov-10	45	22.8	507.4	810.3	520.8		39	34	876	
2010	12	Dec-10	45	26.6	591.4	1214.7	570.5	**5,611**	39	39	994	**9,892**
2011	1	Jan-11	45	30.8	685.0	1289.0	665.8		40	45	1,113	
2011	2	Feb-11	45	34.3	763.2	1007.4	777.1		40	50	1,249	
2011	3	Mar-11	45	30.8	685.3	1041.3	675.8		40	41	1,036	
2011	4	Apr-11	45	25.4	564.6	720.1	546.5		40	38	939	
2011	5	May-11	45	22.2	492.6	360.5	497.7		42	27	649	
2011	6	Jun-11	45	18.6	414.0	168.2	412.0		44	33	752	
2011	7	Jul-11	45	17.8	395.1	36.6	401.8		45	31	697	
2011	8	Aug-11	45	17.8	396.5	85.7	403.0		45	30	677	
2011	9	Sep-11	46	19.9	432.5	205.7	447.2		45	35	789	
2011	10	Oct-11	46	17.8	387.5	470.8	399.8		40	26	656	
2011	11	Nov-11	47	21.4	455.7	952.1	434.0		40	30	754	
2011	12	Dec-11	47	28.9	614.9	978.4	652.5	**6,313**	40	43	1,063	**10,375**
2012	1	Jan-12	47	27.6	586.7	1184.0	593.5		40	40	1,001	
2012	2	Feb-12	47	32.3	686.3	913.4	723.5		40	45	1,120	
2012	3	Mar-12	47	26.5	564.4	991.7	567.2		40	38	952	
2012	4	Apr-12	47	26.8	570.7	676.1	563.4		40	36	907	
2012	5	May-12	47	21.7	462.2	276.5	488.1		40	28	701	
2012	6	Jun-12	47	21.3	452.7	155.5	453.8		45	33	736	
2012	7	Jul-12	48	18.8	390.9	13.3	403.4		46	34	747	
2012	8	Aug-12	48	19.1	398.0	59.5	411.0		46	36	784	
2012	9	Sep-12	49	17.4	355.4	178.2	377.0		46	35	762	
2012	10	Oct-12	49	19.8	404.7	574.9	391.2		40	28	706	
2012	11	Nov-12	49	24.0	490.6	1010.5	454.5		40	33	833	
2012	12	Dec-12	49	30.6	625.3	1328.4	576.2	**6,003**	40	42	1,046	**10,294**
2013	1	Jan-13	49	41.2	840.5	1291.6	820.7		40	47	1,163	
2013	2	Feb-13	49	35.1	715.9	927.5	749.6		37	41	1,114	
2013	3	Mar-13	50	28.2	563.7	1076.5	545.5		38	36	951	
2013	4	Apr-13	50	31.6	631.1	785.1	596.8		38	37	972	
2013	5	May-13	50	23.2	463.2	332.8	475.2		38	31	812	
2013	6	Jun-13	50	20.3	405.6	134.7	411.9		43	30	692	
2013	7	Jul-13	50	23.5	470.4	82.6	465.8		42	33	778	
2013	8	Aug-13	50	22.6	452.5	77.7	461.0		44	32	727	
2013	9	Sep-13	50	22.8	455.5	179.7	476.6		44	33	747	
2013	10	Oct-13	50	21.8	435.4	458.2	450.8		38	24	633	
2013	11	Nov-13	50	28.9	577.7	886.6	572.2		38	33	859	
2013	12	Dec-13	50	42.0	840.0	1339.9	788.1	**6,814**	38	52	1,365	**10,813**
2014	1	Jan-14	50	44.9	897.4	1,200	900.3		38	43	1,141	
2014	2	Feb-14	50	26.8	535.0	1,188	504.1		38	41	1,083	
2014	3	Mar-14	49	38.1	777.0	1,121	747.7		38	46	1,210	
2014	4	Apr-14	49	22.3	455.8	691	445.0		38	38	997	
2014	5	May-14	49	22.6	461.4	380	461.6		39	30	758	
2014	6	Jun-14	48	20.3	423.5	158	424.1		45	36	793	
2014	7	Jul-14	48	19.3	402.7	35	409.9		45	32	706	
2014	8	Aug-14	49	22.2	453.6	104	455.6		45	33	739	
2014	9	Sep-14	49	18.5	378.1	274	376.0		44	31	713	
2014	10	Oct-14	49	22.9	467.2	521	467.0		39	25	651	

Northland Utilities (NWT) Limited (Northland)
2023 Amended General Rate Application (GRA)
Enterprise - Data

Enterprise

			Residential						Commercial			
Year	Month	monthly	MRCNT	MRENCNS (MWh)	MRUPC (kWh)	MHDD (Hay River)	Normalized UPC (kWh)	Annual Normalized UPC (kWh)	MCCNT	MCENCNS (MWh)	MCUPC (kWh)	Annual UPC (kWh)
2014	11	Nov-14	48	29.2	608.4	910	597.2		39	33	853	
2014	12	Dec-14	50	43.5	869.4	1,144	866.1	**6,655**	39	44	1,118	**10,762**
2015	1	Jan-15	50	37.4	748.6	1,225	745.3		39	45	1,150	
2015	2	Feb-15	50	27.4	548.2	1,104	538.2		39	37	936	
2015	3	Mar-15	50	32.9	657.2	955	669.1		39	46	1,187	
2015	4	Apr-15	50	19.4	388.0	571	406.7		39	30	765	
2015	5	May-15	50	21.0	419.9	305	438.8		39	26	663	
2015	6	Jun-15	50	22.2	443.9	126	452.3		44	35	795	
2015	7	Jul-15	50	15.4	308.2	67	307.3		45	31	679	
2015	8	Aug-15	50	19.3	385.3	98	388.9		45	34	761	
2015	9	Sep-15	52	31.5	605.4	264	605.7		45	37	822	
2015	10	Oct-15	52	22.5	432.4	508	435.5		38	23	614	
2015	11	Nov-15	54	31.5	583.0	768	607.0		39	39	990	
2015	12	Dec-15	54	34.2	632.8	1,025	659.0	**6,254**	39	38	987	**10,349**
2016	1	Jan-16	54	30.7	569.4	1,087	600.1		39	35	900	
2016	2	Feb-16	54	31.1	576.7	1,050	580.1		38	39	1,014	
2016	3	Mar-16	54	29.4	544.3	925	563.6		39	37	956	
2016	4	Apr-16	54	22.4	415.2	683	406.3		39	30	778	
2016	5	May-16	53	24.4	459.6	312	476.7		39	32	833	
2016	6	Jun-16	53	21.9	412.3	105	425.9		45	34	752	
2016	7	Jul-16	53	15.7	295.9	47	300.1		45	27	608	
2016	8	Aug-16	54	18.5	341.9	79	350.0		47	33	703	
2016	9	Sep-16	54	27.6	510.3	250	514.2		48	32	674	
2016	10	Oct-16	54	20.6	381.4	566	370.0		42	30	718	
2016	11	Nov-16	54	27.6	510.3	722	545.6		43	36	828	
2016	12	Dec-16	54	36.3	671.8	1,191	656.7	**5,789**	43	51	1,185	**9,951**
2017	1	Jan-17	54	28.5	527.6	1,072	562.1		43	42	972	
2017	2	Feb-17	53	29.8	562.1	948	590.8		42	43	1,027	
2017	3	Mar-17	54	30.6	566.9	1,033	559.3		42	54	1,280	
2017	4	Apr-17	54	21.7	401.6	667	396.5		42	29	695	
2017	5	May-17	54	27.2	503.3	284	527.4		42	34	805	
2017	6	Jun-17	54	20.6	381.7	152	383.8		48	31	640	
2017	7	Jul-17	54	19.5	362.0	56	364.0		48	30	619	
2017	8	Aug-17	56	18.8	335.9	60	348.7		48	33	681	
2017	9	Sep-17	56	23.7	423.2	205	438.2		48	41	849	
2017	10	Oct-17	55	26.0	473.6	507	476.9		42	30	722	
2017	11	Nov-17	55	29.9	542.8	976	515.3		42	42	996	
2017	12	Dec-17	55	35.0	636.9	1,084	648.4	**5,811**	42	46	1,086	**10,373**
2018	1	Jan-18	56	38.8	692.8	1,265	679.5		42	47	1,116	
2018	2	Feb-18	56	34.9	624.0	1,044	629.0		42	44	1,036	
2018	3	Mar-18	56	33.9	605.1	992	607.8		42	46	1,085	
2018	4	Apr-18	56	26.3	470.0	723	451.1		42	36	862	
2018	5	May-18	56	28.2	504.0	327	517.5		42	35	839	
2018	6	Jun-18	56	23.1	412.3	157	413.0		48	33	677	
2018	7	Jul-18	57	22.7	398.0	74	395.4		47	31	656	
2018	8	Aug-18	57	22.8	400.5	119	398.8		47	34	729	
2018	9	Sep-18	59	23.8	403.5	425	364.0		47	31	662	
2018	10	Oct-18	59	31.6	536.2	566	524.9		46	34	736	
2018	11	Nov-18	59	32.9	558.1	880	554.3		40	36	912	
2018	12	Dec-18	59	41.9	711.0	1,046	731.8	**6,267**	40	47	1,183	**10,495**
2019	1	Jan-19	59	40.3	682.3	1,223	679.4		40	47	1,175	
2019	2	Feb-19	59	39.7	673.7	1,153	651.5		40	38	960	
2019	3	Mar-19	59	34.9	591.5	710	664.1		39	37	955	
2019	4	Apr-19	59	26.8	453.4	567	473.3		40	20	511	
2019	5	May-19	59	29.7	504.1	433	491.3		41	33	797	
2019	6	Jun-19	59	28.4	480.7	196	471.8		45	37	818	
2019	7	Jul-19	59	26.5	448.5	100	439.5		45	22	487	
2019	8	Aug-19	59	23.2	392.9	153	382.8		45	28	624	
2019	9	Sep-19	59	24.7	419.2	265	419.3		46	29	636	
2019	10	Oct-19	58	28.9	498.7	516	499.7		46	31	671	
2019	11	Nov-19	59	30.6	519.0	849	522.9		40	31	774	
2019	12	Dec-19	59	47.2	800.6	1,227	776.8	**6,472**	38	41	1,087	**9,495**
2020	1	Jan-20	59	45.1	764.2	1,289	744.9		39	46	1,185	
2020	2	Feb-20	59	42.0	711.8	1,106	701.4		40	37	917	
2020	3	Mar-20	59	33.2	563.3	1,078	544.7		39	34	861	
2020	4	Apr-20	59	34.1	577.4	734	555.8		41	31	768	
2020	5	May-20	59	26.9	456.8	460	437.3		37	39	1,045	
2020	6	Jun-20	59	28.7	486.2	207	474.7		41	32	783	
2020	7	Jul-20	59	27.8	470.8	76	467.9		47	30	631	
2020	8	Aug-20	59	24.6	416.3	116	415.4		48	22	455	
2020	9	Sep-20	59	30.3	512.9	273	510.9		48	31	648	
2020	10	Oct-20	59	29.0	491.4	586	475.3		48	32	658	
2020	11	Nov-20	58	36.0	621.2	927	605.7		39	36	918	
2020	12	Dec-20	58	41.0	706.0	1,077	719.3	**6,653**	39	42	1,089	**9,959**
2021	1	Jan-21	58	44.8	772.3	1,099	800.1		38	38	988	
2021	2	Feb-21	58	39.1	674.8	1,227	634.3		39	46	1,169	
2021	3	Mar-21	59	41.8	708.2	1,031	701.4		40	41	1,026	
2021	4	Apr-21	59	33.3	564.3	698	551.5		41	38	928	
2021	5	May-21	59	27.9	472.2	403	466.8		41	35	845	
2021	6	Jun-21	59	27.0	458.2	146	461.7		47	37	777	
2021	7	Jul-21	59	27.7	469.9	64	469.8		47	32	691	
2021	8	Aug-21	59	23.8	404.1	118	402.7		47	33	697	
2021	9	Sep-21	60	23.8	396.7	233	404.7		47	37	792	
2021	10	Oct-21	60	27.4	456.1	458	471.6		42	30	713	
2021	11	Nov-21	60	29.5	492.5	822	503.0		43	31	717	
2021	12	Dec-21	60	41.2	687.5	1,337	636.4	**6,504**	40	33	825	**10,168**
2022	1	Jan-22	60	52.6	875.9	1,263	863.2		43	48	1,121	
2022	2	Feb-22	60	39.6	660.4	1,200	626.7		42	38	904	
2022	3	Mar-22	60	36.9	614.2	1,047	603.3		43	52	1,200	
2022	4	Apr-22	60	28.8	480.0	707	465.2		43	39	911	
2022	5	May-22	59	26.3	445.9	393	442.9		42	37	875	
2022	6	Jun-22					422.9				818	
2022	7	Jul-22					399.7				487	
2022	8	Aug-22					376.8				624	
2022	9	Sep-22					407.1				636	
2022	10	Oct-22					500.5				671	
2022	11	Nov-22					530.9				774	
2022	12	Dec-22					719.0	**6,358**			1,087	**10,108**
2023	1	Jan-23					640.3				1,175	
2023	2	Feb-23					623.7				960	
2023	3	Mar-23					610.4				955	
2023	4	Apr-23					440.3				511	
2023	5	May-23					512.1				797	
2023	6	Jun-23					422.9				818	
2023	7	Jul-23					399.7				487	
2023	8	Aug-23					376.8				624	
2023	9	Sep-23					407.1				636	
2023	10	Oct-23					500.5				671	
2023	11	Nov-23					530.9				774	
2023	12	Dec-23					719.0	**6,184**			1,087	**9,495**

Northland Utilities (NWT) Limited (Northland)
2023 Amended General Rate Application (GRA)
Enterprise - Regression

ENTERPRISE
Summary Output, Residential
Data: 2005:1 - 2019:12

Regression Statistics	
Multiple R	0.808857206
R Square	0.65424998
Adjusted R Square	0.652307564
Standard Error	75.01436412
Observations	180

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	1895354.153	1895354	336.8228	6.55872E-43
Residual	178	1001633.559	5627.155		
Total	179	2896987.712			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
INTERCEPT	351.5068574	9.938182786	35.36933	1.97E-82	331.8950374	371.118677	331.895037	371.118677
MHDD	0.247606263	0.01349152	18.35273	6.56E-43	0.220982356	0.27423017	0.22098236	0.27423017

Summary Output, Commercial
Data: 2005:1 - 2019:12

Regression Statistics	
Multiple R	0.686161034
R Square	0.470816964
Adjusted R Square	0.467844026
Standard Error	162.8388535
Observations	180

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	4199351.845	4199352	158.3675	2.17745E-26
Residual	178	4719935.616	26516.49		
Total	179	8919287.461			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
INTERCEPT	691.2307513	21.57349876	32.04073	7.99E-76	648.6580211	733.803481	648.658021	733.803481
MHDD	0.368559468	0.029286972	12.58442	2.18E-26	0.310765116	0.42635382	0.31076512	0.42635382

Northland Utilities (NWT) Limited (Northland)
2023 Amended General Rate Application (GRA)
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K'atl'odeeche First Nation Reserve

			Residential							Commercial			
Year	Month	monthly	MRCNT	MRENCNS (MWh)	UPC (kWh)	MHDD (Hay River)	Normalized UPC (kWh)	Annual Normalized UPC (kWh)	MCCNT	MCENCNS (MWh)	UPC (kWh)	Annual UPC (kWh)
2005	1	Jan-05	81	82	1,013	1,260	1,000.7		24	93	3,883	
2005	2	Feb-05	81	59	731	1,034	738.9		23	80	3,489	
2005	3	Mar-05	80	58	722	949	735.8		23	80	3,472	
2005	4	Apr-05	80	52	646	542	673.1		23	78	3,378	
2005	5	May-05	78	54	691	407	684.0		23	82	3,545	
2005	6	Jun-05	78	46	591	209	578.6		23	74	3,230	
2005	7	Jul-05	79	43	544	86	538.4		25	70	2,804	
2005	8	Aug-05	80	46	576	143	567.8		25	69	2,769	
2005	9	Sep-05	80	45	567	308	555.7		24	81	3,385	
2005	10	Oct-05	79	55	698	474	710.1		27	92	3,424	
2005	11	Nov-05	80	57	718	767	743.1		25	87	3,461	
2005	12	Dec-05	82	63	768	866	836.6	**8,363**	25	90	3,617	**40,457**
2006	1	Jan-06	83	76	913	1,165	924.9		24	94	3,929	
2006	2	Feb-06	81	62	767	927	802.3		24	87	3,633	
2006	3	Mar-06	80	58	725	904	750.9		24	104	4,339	
2006	4	Apr-06	80	52	646	497	684.8		23	88	3,830	
2006	5	May-06	80	50	626	312	643.9		24	86	3,604	
2006	6	Jun-06	88	50	571	98	586.7		22	73	3,340	
2006	7	Jul-06	88	52	591	85	585.2		23	82	3,550	
2006	8	Aug-06	90	49	550	90	555.6		24	67	2,802	
2006	9	Sep-06	89	50	563	203	579.1		23	77	3,341	
2006	10	Oct-06	89	61	681	524	680.4		23	87	3,791	
2006	11	Nov-06	89	69	772	1,042	725.2		23	89	3,850	
2006	12	Dec-06	89	68	764	925	817.6	**8,337**	23	85	3,704	**43,713**
2007	1	Jan-07	90	86	957	1,108	983.6		22	92	4,184	
2007	2	Feb-07	90	73	812	1,168	784.2		22	87	3,954	
2007	3	Mar-07	90	69	771	1,100	745.7		22	92	4,198	
2007	4	Apr-07	90	71	784	560	806.9		22	86	3,894	
2007	5	May-07	91	53	584	368	587.1		22	76	3,452	
2007	6	Jun-07	92	54	585	161	585.0		22	82	3,734	
2007	7	Jul-07	92	54	584	38	590.6		22	79	3,595	
2007	8	Aug-07	91	45	493	187	473.7		22	71	3,218	
2007	9	Sep-07	93	57	613	366	586.4		22	84	3,832	
2007	10	Oct-07	96	59	613	489	621.3		22	82	3,748	
2007	11	Nov-07	93	64	684	850	687.5		22	88	3,984	
2007	12	Dec-07	93	68	728	1,188	712.5	**8,164**	22	83	3,774	**45,567**
2008	1	Jan-08	93	97	1,039	1,215	1,037.5		22	107	4,876	
2008	2	Feb-08	92	78	843	1,202	807.1		22	88	4,010	
2008	3	Mar-08	91	68	747	1,091	723.8		22	89	4,053	
2008	4	Apr-08	91	68	752	689	740.4		23	88	3,842	
2008	5	May-08	91	61	671	358	677.4		23	86	3,739	
2008	6	Jun-08	91	57	624	155	625.7		23	71	3,066	
2008	7	Jul-08	92	47	512	35	519.2		23	80	3,484	
2008	8	Aug-08	90	53	594	103	596.7		24	77	3,194	
2008	9	Sep-08	91	50	547	315	533.8		24	72	2,998	
2008	10	Oct-08	91	55	609	478	620.4		24	78	3,259	
2008	11	Nov-08	91	72	794	778	816.8		24	92	3,839	
2008	12	Dec-08	91	71	780	1,281	741.1	**8,440**	24	83	3,441	**43,800**
2009	1	Jan-09	91	100	1,100	1,238	1,093.0		24	91	3,794	
2009	2	Feb-09	91	74	810	1,085	804.3		24	83	3,479	
2009	3	Mar-09	91	84	918	1,116	888.0		24	94	3,933	
2009	4	Apr-09	90	67	750	623	755.9		24	83	3,448	
2009	5	May-09	91	53	584	490	555.9		22	72	3,277	
2009	6	Jun-09	90	57	637	193	628.5		24	83	3,469	
2009	7	Jul-09	90	52	583	101	572.9		24	72	3,007	
2009	8	Aug-09	88	51	574	88	580.6		24	68	2,841	
2009	9	Sep-09	87	50	575	177	597.9		24	71	2,961	
2009	10	Oct-09	89	53	590	560	579.7		24	75	3,144	
2009	11	Nov-09	93	70	748	825	758.7		24	95	3,979	
2009	12	Dec-09	93	71	769	1,163	760.1	**8,575**	24	90	3,752	**41,082**
2010	1	Jan-10	93	95	1,021	1,229	1,016.2		24	108	4,489	
2010	2	Feb-10	93	70	754	900	796.7		24	88	3,668	
2010	3	Mar-10	93	63	682	719	756.8		24	88	3,669	
2010	4	Apr-10	94	63	675	491	715.6		24	85	3,528	
2010	5	May-10	92	57	623	402	617.4		24	87	3,635	
2010	6	Jun-10	91	50	551	120	561.1		25	76	3,031	
2010	7	Jul-10	89	48	542	45	547.3		25	69	2,777	
2010	8	Aug-10	89	51	571	109	572.1		24	66	2,747	
2010	9	Sep-10	88	49	555	294	548.1		25	68	2,720	
2010	10	Oct-10	89	56	631	464	645.3		25	86	3,444	
2010	11	Nov-10	90	59	653	810	666.7		25	90	3,590	
2010	12	Dec-10	90	69	765	1,215	743.2	**8,186**	26	98	3,778	**41,076**
2011	1	Jan-11	91	79	866	1,289	846.0		26	94	3,603	
2011	2	Feb-11	90	75	831	1,007	846.1		26	101	3,901	
2011	3	Mar-11	90	72	803	1,041	792.5		26	99	3,801	
2011	4	Apr-11	89	55	617	720	597.6		26	80	3,069	
2011	5	May-11	88	57	647	361	652.6		25	87	3,466	
2011	6	Jun-11	88	50	568	168	565.5		25	75	2,992	
2011	7	Jul-11	84	45	532	37	538.6		25	63	2,534	
2011	8	Aug-11	84	50	599	86	605.7		24	66	2,737	
2011	9	Sep-11	85	50	590	206	605.1		24	70	2,919	
2011	10	Oct-11	83	53	633	471	646.1		24	79	3,310	
2011	11	Nov-11	83	63	760	952	737.0		24	89	3,709	
2011	12	Dec-11	84	68	808	978	848.2	**8,281**	24	88	3,667	**39708.70**
2012	1	Jan-12	83	70	849	1,184	856.0		24	83	3,474	
2012	2	Feb-12	83	77	932	913	971.5		24	95	3,948	
2012	3	Mar-12	83	67	802	992	804.8		24	91	3,779	
2012	4	Apr-12	83	58	701	676	693.6		24	83	3,453	
2012	5	May-12	81	55	681	277	708.6		24	87	3,610	
2012	6	Jun-12	82	48	588	156	589.5		24	76	3,181	
2012	7	Jul-12	81	49	605	13	618.2		24	70	2,909	
2012	8	Aug-12	81	47	575	60	588.5		24	64	2,669	
2012	9	Sep-12	81	47	582	178	604.7		24	67	2,789	
2012	10	Oct-12	80	55	689	575	675.1		24	83	3,445	
2012	11	Nov-12	81	58	721	1,011	683.3		24	83	3,458	
2012	12	Dec-12	81	69	847	1,328	795.1	**8,589**	23	85	3,696	**40411.93**
2013	1	Jan-13	81	83	1,025	1,292	1,003.6		23	91	3,942	
2013	2	Feb-13	80	72	900	928	935.6		23	88	3,845	
2013	3	Mar-13	84	66	780	1,077	760.7		24	82	3,405	
2013	4	Apr-13	85	65	763	785	726.7		24	83	3,441	
2013	5	May-13	84	54	640	333	652.8		24	77	3,222	
2013	6	Jun-13	81	49	610	135	616.5		24	74	3,100	
2013	7	Jul-13	80	47	592	83	586.9		24	60	2,509	
2013	8	Aug-13	80	46	578	78	587.1		24	62	2,563	
2013	9	Sep-13	81	50	613	180	635.8		24	58	2,397	
2013	10	Oct-13	82	52.2	637.1	458.2	653.4		24	70	2,915	
2013	11	Nov-13	81	66.9	825.8	886.6	820.0		24	75	3,145	
2013	12	Dec-13	82	79.3	966.9	1339.9	912.1	**8,891**	24	80	3,319	**37,802**
2014	1	Jan-14	82	81.8	997.3	1,200	1,000.3		23	72	3,141	
2014	2	Feb-14	82	62.5	762.0	1,188	729.4		23	67	2,934	
2014	3	Mar-14	81	75.9	937.1	1,121	906.2		23	83	3,620	
2014	4	Apr-14	81	51.8	638.9	691	627.5		23	61	2,669	
2014	5	May-14	81	48.4	597.6	380	597.8		23	61	2,652	
2014	6	Jun-14	76	42.8	563.7	158	564.3		23	54	2,344	
2014	7	Jul-14	77	47.2	613.2	35	620.8		23	54	2,340	
2014	8	Aug-14	78	48.3	619.7	104	621.7		23	58	2,528	
2014	9	Sep-14	79	47.5	601.6	274	599.3		24	52	2,158	
2014	10	Oct-14	80	50.9	636.0	521	635.7		24	65	2,719	

Northland Utilities (NWT) Limited (Northland)
2023 Amended General Rate Application (GRA)
K'atl'odeeche - Data

K'atl'odeeche First Nation Reserve

			Residential							Commercial			
Year	Month	monthly	MRCNT	MRENCNS (MWh)	UPC (kWh)	MHDD (Hay River)	Normalized UPC (kWh)	Annual Normalized UPC (kWh)	MCCNT	MCENCNS (MWh)	UPC (kWh)	Annual UPC (kWh)
2014	11	Nov-14	80	67.1	838.4	910	826.6		24	80	3,322	
2014	12	Dec-14	80	69.9	874.2	1,144	870.6	**8,600**	25	76	3,040	**33,467**
2015	1	Jan-15	81	71.6	884.1	1,225	880.7		25	77	3,066	
2015	2	Feb-15	81	64.9	800.9	1,104	790.3		25	70	2,805	
2015	3	Mar-15	81	74.3	916.9	955	929.5		25	92	3,683	
2015	4	Apr-15	81	40.3	497.2	571	516.9		25	60	2,397	
2015	5	May-15	81	46.2	570.8	305	590.8		25	66	2,656	
2015	6	Jun-15	78	49.6	636.2	126	645.1		25	56	2,229	
2015	7	Jul-15	78	38.4	492.1	67	491.2		25	45	1,810	
2015	8	Aug-15	78	46.0	589.5	98	593.4		25	52	2,094	
2015	9	Sep-15	77	45.1	586.0	264	586.3		25	52	2,075	
2015	10	Oct-15	76	52.6	692.3	508	695.6		25	78	3,132	
2015	11	Nov-15	79	62.6	792.3	768	817.6		25	77	3,061	
2015	12	Dec-15	80	60.6	757.8	1,025	785.4	**8,323**	25	77	3,068	**32,074**
2016	1	Jan-16	80	58.5	730.7	1,087	763.1		25	69	2,779	
2016	2	Feb-16	79	62.2	787.9	1,050	791.5		25	77	3,087	
2016	3	Mar-16	78	53.4	685.2	925	705.6		25	67	2,677	
2016	4	Apr-16	78	47.2	604.8	683	595.4		25	64	2,552	
2016	5	May-16	79	48.9	619.1	312	637.2		25	63	2,509	
2016	6	Jun-16	78	45.7	585.7	105	600.0		25	53	2,126	
2016	7	Jul-16	77	39.3	510.1	47	514.5		25	43	1,702	
2016	8	Aug-16	78	45.3	581.0	79	589.5		25	50	1,993	
2016	9	Sep-16	78	45.0	577.4	250	581.6		25	50	2,006	
2016	10	Oct-16	77	47.9	621.5	566	609.4		25	61	2,459	
2016	11	Nov-16	78	55.5	711.5	722	748.8		25	76	3,054	
2016	12	Dec-16	78	71.6	917.4	1,191	901.4	**8,038**	25	96	3,837	**30,781**
2017	1	Jan-17	78	60.8	779.8	1,072	816.2		25	72	2,873	
2017	2	Feb-17	79	53.2	673.2	948	703.5		25	70	2,803	
2017	3	Mar-17	78	56.3	721.4	1,033	713.5		25	75	3,007	
2017	4	Apr-17	77	41.2	535.4	667	530.0		25	58	2,310	
2017	5	May-17	77	53.2	690.5	284	716.0		25	74	2,957	
2017	6	Jun-17	75	37.5	500.1	152	502.3		24	54	2,235	
2017	7	Jul-17	74	41.1	555.5	56	557.6		24	53	2,223	
2017	8	Aug-17	74	44.8	605.2	60	618.8		24	55	2,304	
2017	9	Sep-17	75	40.5	539.9	205	555.7		24	53	2,214	
2017	10	Oct-17	75	53.8	718.0	507	721.5		24	77	3,206	
2017	11	Nov-17	74	51.5	696.0	976	667.0		23	69	3,020	
2017	12	Dec-17	75	60.0	800.3	1,084	812.3	**7,914**	24	76	3,159	**32,311**
2018	1	Jan-18	75	72.3	963.9	1,265	949.8		24	75	3,104	
2018	2	Feb-18	75	48.0	639.4	1,044	644.7		24	62	2,575	
2018	3	Mar-18	75	51.4	685.5	992	688.4		24	72	3,011	
2018	4	Apr-18	75	46.9	625.0	723	605.0		24	70	2,933	
2018	5	May-18	76	46.6	612.6	327	626.8		24	62	2,602	
2018	6	Jun-18	76	42.9	564.5	157	565.3		24	58	2,421	
2018	7	Jul-18	74	40.8	551.9	74	549.1		26	56	2,169	
2018	8	Aug-18	75	46.9	625.6	119	623.9		26	62	2,397	
2018	9	Sep-18	75	42.4	564.7	425	523.0		26	64	2,456	
2018	10	Oct-18	76	50.5	663.9	566	652.0		26	79	3,032	
2018	11	Nov-18	77	48.9	635.3	880	631.2		26	79	3,039	
2018	12	Dec-18	77	53.1	689.0	1,046	711.0	**7,770**	25	78	3,111	**32,850**
2019	1	Jan-19	77	55.5	720.4	1,223	717.3		26	85	3,255	
2019	2	Feb-19	78	56.1	718.8	1,153	695.3		26	73	2,789	
2019	3	Mar-19	78	51.0	653.6	710	730.3		26	74	2,861	
2019	4	Apr-19	78	45.0	577.1	567	598.1		26	71	2,749	
2019	5	May-19	84	46.6	555.0	433	541.5		26	75	2,888	
2019	6	Jun-19	84	44.9	534.6	196	525.2		26	67	2,585	
2019	7	Jul-19	86	44.9	522.0	100	512.5		26	59	2,285	
2019	8	Aug-19	85	35.6	419.4	153	408.8		26	51	1,955	
2019	9	Sep-19	90	42.3	469.7	265	469.8		26	57	2,180	
2019	10	Oct-19	90	51.7	575.0	516	576.1		26	74	2,857	
2019	11	Nov-19	90	51.0	566.9	849	571.0		26	66	2,535	
2019	12	Dec-19	90	73.8	819.6	1,227	794.4	**7,140**	26	84	3,227	**32,168**
2020	1	Jan-20	90	63.1	701.6	1,289	681.3		26	72	2,782	
2020	2	Feb-20	90	60.9	676.5	1,106	665.6		27	69	2,573	
2020	3	Mar-20	90	61.2	679.9	1,078	660.3		27	81	2,986	
2020	4	Apr-20	90	54.9	610.5	734	587.7		27	61	2,269	
2020	5	May-20	90	46.0	511.1	460	490.5		27	51	1,888	
2020	6	Jun-20	90	49.1	545.7	207	533.5		27	54	1,993	
2020	7	Jul-20	90	52.2	580.1	76	577.0		28	50	1,790	
2020	8	Aug-20	90	46.6	517.5	116	516.5		28	43	1,524	
2020	9	Sep-20	90	57.2	635.6	273	633.5		28	64	2,278	
2020	10	Oct-20	90	56.4	626.3	586	609.2		29	73	2,521	
2020	11	Nov-20	90	61.4	681.9	927	665.5		29	77	2,645	
2020	12	Dec-20	91	68.3	750.3	1,077	764.3	**7,385**	27	75	2,768	**28,017**
2021	1	Jan-21	91	80.6	885.9	1,099	915.3		29	87	3,005	
2021	2	Feb-21	90	74.8	831.3	1,227	788.6		29	78	2,676	
2021	3	Mar-21	90	64.4	715.3	1,031	708.1		29	74	2,568	
2021	4	Apr-21	90	58.3	647.5	698	634.0		29	71	2,452	
2021	5	May-21	90	49.4	548.9	403	543.3		29	67	2,316	
2021	6	Jun-21	90	48.6	540.3	146	543.9		28	66	2,375	
2021	7	Jul-21	88	52.8	600.5	64	600.4		28	54	1,912	
2021	8	Aug-21	87	47.0	540.4	118	538.9		28	50	1,776	
2021	9	Sep-21	88	50.1	569.8	233	578.2		28	55	1,962	
2021	10	Oct-21	88	54.8	622.8	458	639.2		28	70	2,494	
2021	11	Nov-21	89	62.7	704.9	822	715.9		29	72	2,468	
2021	12	Dec-21	89	77.3	868.9	1,337	815.0	**8,021**	30	78	2,590	**28,595**
2022	1	Jan-22	89	81.7	918.1	1,263	904.7		30	73	2,449	
2022	2	Feb-22	89	65.2	732.8	1,200	697.2		30	71	2,350	
2022	3	Mar-22	89	63.8	716.6	1,047	705.1		30	69	2,316	
2022	4	Apr-22	89	48.4	543.8	707	528.1		29	60	2,066	
2022	5	May-22	80	49.7	621.5	393	618.4		15	21	1,426	
2022	6	Jun-22					525.2				2,414	
2022	7	Jul-22					512.5				2,226	
2022	8	Aug-22					408.8				2,219	
2022	9	Sep-22					469.8				2,283	
2022	10	Oct-22					576.1				3,031	
2022	11	Nov-22					571.0				2,865	
2022	12	Dec-22					794.4	**7,311**			3,166	**28,811**
2023	1	Jan-23					717.3				3,078	
2023	2	Feb-23					695.3				2,722	
2023	3	Mar-23					730.3				2,960	
2023	4	Apr-23					598.1				2,664	
2023	5	May-23					541.5				2,816	
2023	6	Jun-23					525.2				2,414	
2023	7	Jul-23					512.5				2,226	
2023	8	Aug-23					408.8				2,219	
2023	9	Sep-23					469.8				2,283	
2023	10	Oct-23					576.1				3,031	
2023	11	Nov-23					571.0				2,865	
2023	12	Dec-23					794.4	**7,140**			3,166	**32,443**

K'atl'odeeche First Nation Reserve
Summary Output, Residential
Data: 2005:1 - 2019:12

Regression Statistics	
Multiple R	0.833652517
R Square	0.694976519
Adjusted R Square	0.693262903
Standard Error	72.18598657
Observations	180

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	2113307.296	2113307	405.5616	9.11473E-48
Residual	178	927525.365	5210.817		
Total	179	3040832.661			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
INTERCEPT	525.0222711	9.563468778	54.89873	1.6E-113	506.1499046	543.8946377	506.1499046	543.8946377
MHDD	0.26145549	0.012982829	20.13856	9.11E-48	0.235835424	0.287075557	0.235835424	0.287075557

Summary Output, Commercial
Data: 2005:1 - 2019:12

Regression Statistics	
Multiple R	0.56461866
R Square	0.318794232
Adjusted R Square	0.314967233
Standard Error	485.9774572
Observations	180

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	19673624.98	19673625	83.30137	1.51748E-16
Residual	178	42038987.82	236174.1		
Total	179	61712612.8			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
INTERCEPT	2665.681184	64.38410638	41.40278	2.72E-93	2538.626819	2792.735549	2538.626819	2792.735549
MHDD	0.797734977	0.087404253	9.126958	1.52E-16	0.625253095	0.970216859	0.625253095	0.970216859

Northland Utilities (NWT) Limited (Northland)
2023 Amended General Rate Application (GRA)
Fort Providence - Data

Fort Providence

Residential									Commercial				
			MRCNT	MRENCNS	UPC	MHDD	Normalized	Annual Normalized	MCCNT	MCENCNS	UPC	Annual
Year	Month	monthly		(MWh)	(kWh)	(Hay River)	UPC (kWh)	UPC (kWh)		(MWh)	(kWh)	UPC (kWh)
2005	1	Jan-05	249	140	561	1,260	552.1		77	181	2,356	
2005	2	Feb-05	250	121	486	1,034	508.4		77	113	1,472	
2005	3	Mar-05	250	115	461	949	486.1		80	166	2,073	
2005	4	Apr-05	247	122	494	542	515.4		83	79	949	
2005	5	May-05	248	75	301	407	297.6		82	113	1,377	
2005	6	Jun-05	247	93	375	209	367.7		80	110	1,381	
2005	7	Jul-05	248	88	357	86	349.1		78	104	1,333	
2005	8	Aug-05	249	85	342	143	336.1		78	112	1,441	
2005	9	Sep-05	253	105	415	308	410.2		76	126	1,653	
2005	10	Oct-05	251	102	406	474	412.8		77	103	1,333	
2005	11	Nov-05	251	124	494	767	514.4		81	118	1,453	
2005	12	Dec-05	251	106	421	866	461.6	**5,212**	83	120	1,450	**18,272**
2006	1	Jan-06	248	143	576	1,165	581.6		80	148	1,846	
2006	2	Feb-06	249	122	491	927	528.7		80	135	1,682	
2006	3	Mar-06	250	117	469	904	500.7		76	128	1,678	
2006	4	Apr-06	250	106	422	497	450.4		77	120	1,560	
2006	5	May-06	250	94	375	312	384.5		75	103	1,379	
2006	6	Jun-06	254	89	349	98	357.7		75	108	1,441	
2006	7	Jul-06	253	93	369	85	361.9		75	95	1,261	
2006	8	Aug-06	255	89	348	90	350.2		73	125	1,707	
2006	9	Sep-06	254	99	389	203	399.6		73	115	1,573	
2006	10	Oct-06	256	105	409	524	408.2		74	112	1,509	
2006	11	Nov-06	253	120	476	1,042	456.3		73	132	1,803	
2006	12	Dec-06	255	135	528	925	559.9	**5,340**	72	108	1,500	**18,939**
2007	1	Jan-07	257	143	555	1,108	568.7		72	151	2,098	
2007	2	Feb-07	254	126	497	1,168	499.5		72	140	1,945	
2007	3	Mar-07	253	128	504	1,100	507.2		73	121	1,654	
2007	4	Apr-07	253	112	444	560	462.8		75	110	1,466	
2007	5	May-07	249	97	388	368	390.2		77	138	1,789	
2007	6	Jun-07	251	97	385	161	384.2		80	119	1,493	
2007	7	Jul-07	252	87	344	38	343.4		85	114	1,346	
2007	8	Aug-07	251	101	403	187	390.5		91	112	1,233	
2007	9	Sep-07	254	99	391	366	377.6		91	106	1,161	
2007	10	Oct-07	252	113	450	489	454.5		86	125	1,455	
2007	11	Nov-07	262	137	525	850	533.3		79	143	1,812	
2007	12	Dec-07	259	156	603	1,188	596.3	**5,508**	75	135	1,799	**19,251**
2008	1	Jan-08	276	159	575	1,215	573.2		77	145	1,884	
2008	2	Feb-08	278	143	516	1,202	513.9		76	149	1,966	
2008	3	Mar-08	282	129	457	1,091	461.1		76	120	1,581	
2008	4	Apr-08	283	128	452	689	451.8		77	111	1,441	
2008	5	May-08	278	110	397	358	400.4		79	114	1,443	
2008	6	Jun-08	278	114	409	155	409.4		81	118	1,451	
2008	7	Jul-08	277	84	302	35	301.9		82	99	1,210	
2008	8	Aug-08	276	109	394	103	394.5		81	132	1,628	
2008	9	Sep-08	278	110	395	315	388.5		79	97	1,223	
2008	10	Oct-08	277	108	390	478	396.0		76	108	1,421	
2008	11	Nov-08	273	144	529	778	548.5		75	138	1,843	
2008	12	Dec-08	276	134	484	1,281	464.4	**5,304**	75	122	1,623	**18,713**
2009	1	Jan-09	274	176	644	1,238	638.5		73	154	2,107	
2009	2	Feb-09	275	141	513	1,085	528.4		73	131	1,789	
2009	3	Mar-09	277	132	476	1,116	476.9		74	129	1,748	
2009	4	Apr-09	276	132	478	623	487.9		73	113	1,553	
2009	5	May-09	276	107	387	490	371.1		77	124	1,613	
2009	6	Jun-09	279	99	354	193	348.5		75	102	1,365	
2009	7	Jul-09	279	108	386	101	376.2		77	110	1,432	
2009	8	Aug-09	276	104	378	88	380.2		75	122	1,629	
2009	9	Sep-09	272	109	401	177	415.5		75	114	1,524	
2009	10	Oct-09	275	118	431	560	425.3		69	110	1,594	
2009	11	Nov-09	280	140	499	825	511.3		69	125	1,814	
2009	12	Dec-09	270	136	503	1,163	500.4	**5,460**	67	106	1,580	**19,746**
2010	1	Jan-10	279	171	614	1,229	609.4		71	178	2,507	
2010	2	Feb-10	278	135	485	900	526.8		73	130	1,777	
2010	3	Mar-10	281	125	446	719	504.8		72	112	1,554	
2010	4	Apr-10	284	133	470	491	499.0		73	117	1,607	
2010	5	May-10	282	125	445	402	441.9		74	117	1,579	
2010	6	Jun-10	280	118	420	120	425.2		75	116	1,552	
2010	7	Jul-10	281	113	402	45	400.7		74	129	1,739	
2010	8	Aug-10	283	98	347	109	346.4		74	108	1,464	
2010	9	Sep-10	286	106	370	294	367.6		74	125	1,689	
2010	10	Oct-10	286	121	424	464	432.6		74	108	1,457	
2010	11	Nov-10	284	121	425	810	439.5		69	104	1,512	
2010	12	Dec-10	288	145	503	1,215	492.9	**5,487**	68	128	1,882	**20,319**
2011	1	Jan-11	291	181	621	1,289	608.0		69	151	2,196	
2011	2	Feb-11	287	156	544	1,007	570.8		69	133	1,934	
2011	3	Mar-11	290	159	547	1,041	558.9		69	141	2,040	
2011	4	Apr-11	289	135	468	720	463.8		69	120	1,746	
2011	5	May-11	288	133	462	361	464.4		69	107	1,558	
2011	6	Jun-11	286	104	362	168	360.6		73	95	1,297	
2011	7	Jul-11	288	110	382	37	381.4		73	114	1,559	
2011	8	Aug-11	286	104	364	86	366.8		74	108	1,460	
2011	9	Sep-11	288	102	356	206	365.6		73	99	1,355	
2011	10	Oct-11	287	112	390	471	397.6		69	95	1,382	
2011	11	Nov-11	291	119	409	952	402.8		69	93	1,342	
2011	12	Dec-11	291	144	495	978	519.6	**5,460**	69	109	1,582	**19,449**
2012	1	Jan-12	290	172	594	1,184	595.8		67	134	2,002	
2012	2	Feb-12	285	156	547	913	587.1		68	120	1,770	
2012	3	Mar-12	289	152	528	992	546.5		68	126	1,856	
2012	4	Apr-12	290	140	482	676	483.8		69	126	1,832	
2012	5	May-12	292	128	440	277	455.2		69	111	1,603	
2012	6	Jun-12	292	106	363	156	363.7		72	92	1,282	
2012	7	Jul-12	285	105	369	13	371.8		72	107	1,487	
2012	8	Aug-12	287	110	384	60	390.2		72	116	1,613	
2012	9	Sep-12	286	97	339	178	353.0		73	110	1,512	
2012	10	Oct-12	285	104	365	575	357.3		70	94	1,346	
2012	11	Nov-12	285	116	408	1,011	393.0		70	100	1,427	
2012	12	Dec-12	289	142	490	1,328	463.4	**5,361**	70	137	1,951	**19,680**
2013	1	Jan-13	289	160	555	1,292	541.4		70	150	2,149	
2013	2	Feb-13	287	168	584	928	622.4		70	147	2,101	
2013	3	Mar-13	285	126	443	1,077	449.1		74	123	1,667	
2013	4	Apr-13	284	120	421	785	407.5		74	119	1,614	
2013	5	May-13	284	138	485	333	491.8		74	120	1,616	
2013	6	Jun-13	281	110	390	135	393.6		77	109	1,410	
2013	7	Jul-13	276	96	347	83	339.8		77	114	1,486	
2013	8	Aug-13	282	107	378	78	381.8		77	122	1,591	
2013	9	Sep-13	281	107	380	180	394.2		76	116	1,525	
2013	10	Oct-13	282	111	392.5	458.2	401.6		74	111	1,497	
2013	11	Nov-13	284	136	478.5	886.6	475.3		74	130	1,760	
2013	12	Dec-13	283	155	547.2	1339.9	516.7	**5,415**	75	164	2,180	**20,594**
2014	1	Jan-14	285	157	550.6	1,200	552.4		75	146	1,947	
2014	2	Feb-14	283	134	475.0	1,188	456.8		76	130	1,712	
2014	3	Mar-14	282	131	463.3	1,121	446.1		75	131	1,745	
2014	4	Apr-14	282	116	411.9	691	405.5		75	113	1,513	
2014	5	May-14	284	115	405.5	380	405.6		78	110	1,413	
2014	6	Jun-14	278	101	363.1	158	363.4		79	115	1,458	
2014	7	Jul-14	278	100	358.8	35	363.0		78	129	1,648	
2014	8	Aug-14	281	100	355.8	104	356.9		77	123	1,603	
2014	9	Sep-14	281	97	344.1	274	342.8		79	118	1,494	
2014	10	Oct-14	281	132	470.5	521	470.3		73	103	1,411	
2014	11	Nov-14	280	131	468.5	910	461.9		75	129	1,722	
2014	12	Dec-14	283	148	522.5	1,144	520.5	**5,145**	75	134	1,789	**19,455**
2015	1	Jan-15	284	157	554.1	1,225	552.1		74	138	1,863	

Northland Utilities (NWT) Limited (Northland)
2023 Amended General Rate Application (GRA)
Fort Providence - Data

Fort Providence

Residential									Commercial			
			MRCNT	MRENCNS	UPC	MHDD	Normalized	Annual Normalized	MCCNT	MCENCNS	UPC	Annual
Year	Month	monthly		(MWh)	(kWh)	(Hay River)	UPC (kWh)	UPC (kWh)		(MWh)	(kWh)	UPC (kWh)
2015	2	Feb-15	283	140	493.3	1,104	487.5		74	126	1,697	
2015	3	Mar-15	282	126	446.6	955	453.7		74	128	1,728	
2015	4	Apr-15	283	107	376.7	571	387.7		74	118	1,596	
2015	5	May-15	283	112	396.2	305	407.3		74	113	1,522	
2015	6	Jun-15	281	98	348.1	126	353.0		77	124	1,617	
2015	7	Jul-15	282	90	317.8	67	317.3		79	121	1,535	
2015	8	Aug-15	283	108	381.6	98	383.7		78	112	1,435	
2015	9	Sep-15	280	93	332.4	264	332.5		80	120	1,503	
2015	10	Oct-15	282	115	409.0	508	410.8		76	117	1,533	
2015	11	Nov-15	281	125	445.3	768	459.4		76	126	1,659	
2015	12	Dec-15	284	145	511.0	1,025	526.4	**5,071**	76	133	1,756	**19,445**
2016	1	Jan-16	285	145	507.1	1,087	525.2		76	136	1,787	
2016	2	Feb-16	286	135	472.3	1,050	474.3		76	122	1,611	
2016	3	Mar-16	284	119	419.1	925	430.4		76	130	1,708	
2016	4	Apr-16	285	114	399.7	683	394.5		76	117	1,544	
2016	5	May-16	286	110	383.2	312	393.3		75	105	1,397	
2016	6	Jun-16	283	103	363.7	105	371.8		79	108	1,363	
2016	7	Jul-16	286	94	330.4	47	332.8		79	116	1,470	
2016	8	Aug-16	286	102	357.5	79	362.2		78	111	1,429	
2016	9	Sep-16	287	100	346.7	250	349.0		80	108	1,346	
2016	10	Oct-16	286	121	423.8	566	417.1		75	116	1,551	
2016	11	Nov-16	287	126	439.7	722	460.4		76	120	1,574	
2016	12	Dec-16	287	145	506.9	1,191	498.0	**5,009**	75	135	1,796	**18,577**
2017	1	Jan-17	287	149	518.0	1,072	538.3		75	131	1,751	
2017	2	Feb-17	287	118	410.4	948	427.3		75	123	1,637	
2017	3	Mar-17	287	129	448.6	1,033	444.2		75	133	1,777	
2017	4	Apr-17	287	103	358.5	667	355.6		75	104	1,384	
2017	5	May-17	286	117	407.5	284	421.6		75	111	1,475	
2017	6	Jun-17	284	98	343.5	152	344.7		80	107	1,335	
2017	7	Jul-17	285	91	317.8	56	319.0		80	113	1,412	
2017	8	Aug-17	286	104	365.3	60	372.9		79	105	1,326	
2017	9	Sep-17	287	93	324.9	205	333.7		79	107	1,351	
2017	10	Oct-17	285	111	389.1	507	391.0		80	112	1,403	
2017	11	Nov-17	286	129	452.2	976	436.0		80	123	1,540	
2017	12	Dec-17	285	135	473.1	1,084	479.9	**4,864**	80	126	1,570	**17,962**
2018	1	Jan-18	285	146	511.7	1,265	503.8		83	135	1,631	
2018	2	Feb-18	285	121	423.4	1,044	426.3		83	121	1,463	
2018	3	Mar-18	285	109	381.4	992	383.1		82	119	1,446	
2018	4	Apr-18	285	108	378.4	723	367.3		78	125	1,602	
2018	5	May-18	284	114	403.2	327	411.1		78	98	1,260	
2018	6	Jun-18	281	94	333.6	157	334.0		82	106	1,290	
2018	7	Jul-18	284	97	343.2	74	341.7		82	112	1,367	
2018	8	Aug-18	282	100	355.4	119	354.4		82	103	1,262	
2018	9	Sep-18	284	86	301.9	425	278.6		82	103	1,253	
2018	10	Oct-18	284	115	403.7	566	397.0		79	114	1,437	
2018	11	Nov-18	285	141	494.9	880	492.6		79	145	1,836	
2018	12	Dec-18	285	105	370.1	1,046	382.3	**4,672**	79	124	1,573	**17,420**
2019	1	Jan-19	285	140	492.7	1,223	491.0		79	130	1,643	
2019	2	Feb-19	283	124	437.0	1,153	423.9		79	123	1,559	
2019	3	Mar-19	287	116	402.5	710	445.3		79	119	1,507	
2019	4	Apr-19	280	97	345.7	567	357.4		77	112	1,449	
2019	5	May-19	286	104	362.7	433	355.2		77	105	1,362	
2019	6	Jun-19	278	91	325.7	196	320.4		82	108	1,319	
2019	7	Jul-19	279	88	314.2	100	308.9		82	118	1,434	
2019	8	Aug-19	279	96	345.8	153	339.8		81	101	1,249	
2019	9	Sep-19	283	95	334.1	265	334.1		82	99	1,210	
2019	10	Oct-19	280	107	381.0	516	381.6		78	111	1,422	
2019	11	Nov-19	285	123	429.9	849	432.3		77	109	1,414	
2019	12	Dec-19	283	135	478.0	1,227	464.0	**4,654**	76	138	1,822	**17,391**
2020	1	Jan-20	285	145	507.4	1,289	496.1		77	138	1,790	
2020	2	Feb-20	287	125	434.2	1,106	428.1		78	116	1,485	
2020	3	Mar-20	285	114	399.7	1,078	388.8		78	130	1,661	
2020	4	Apr-20	284	107	377.2	734	364.5		77	104	1,347	
2020	5	May-20	284	111	391.4	460	379.9		77	90	1,174	
2020	6	Jun-20	284	109	383.6	207	376.8		77	87	1,134	
2020	7	Jul-20	283	102	360.1	76	358.3		80	105	1,315	
2020	8	Aug-20	283	100	351.8	116	351.3		80	107	1,338	
2020	9	Sep-20	284	103	363.4	273	362.2		80	104	1,304	
2020	10	Oct-20	285	114	400.4	586	390.9		80	117	1,465	
2020	11	Nov-20	285	124	433.9	927	424.7		76	124	1,636	
2020	12	Dec-20	286	146	510.6	1,077	518.4	**4,840**	75	129	1,716	**17,366**
2021	1	Jan-21	286	145	507.1	1,099	523.5		76	123	1,614	
2021	2	Feb-21	285	127	445.8	1,227	422.0		76	135	1,771	
2021	3	Mar-21	285	127	446.0	1,031	442.0		76	121	1,592	
2021	4	Apr-21	285	123	431.0	698	423.5		76	96	1,268	
2021	5	May-21	285	98	343.8	403	340.7		76	113	1,485	
2021	6	Jun-21	285	101	352.7	146	354.7		76	98	1,295	
2021	7	Jul-21	281	95	337.7	64	337.6		81	115	1,417	
2021	8	Aug-21	285	100	349.8	118	349.0		81	102	1,262	
2021	9	Sep-21	283	99	349.1	233	353.8		81	104	1,280	
2021	10	Oct-21	281	111	393.9	458	403.0		81	126	1,555	
2021	11	Nov-21	284	136	479.7	822	485.9		82	107	1,308	
2021	12	Dec-21	285	138	483.1	1,337	453.1	**4,889**	82	148	1,809	**17,658**
2022	1	Jan-22	285	158	553.6	1,263	546.1		77	131	1,706	
2022	2	Feb-22	285	141	495.0	1,200	475.2		81	106	1,310	
2022	3	Mar-22	285	143	501.8	1,047	495.4		76	105	1,377	
2022	4	Apr-22	284	91	320.3	707	311.5		77	132	1,710	
2022	5	May-22	285	108	379.1	393	377.3		77	116	1,508	
2022	6	Jun-22					333.1				1,315	
2022	7	Jul-22					323.2				1,404	
2022	8	Aug-22					355.7				1,279	
2022	9	Sep-22					315.5				1,272	
2022	10	Oct-22					389.9				1,421	
2022	11	Nov-22					453.6				1,597	
2022	12	Dec-22					442.1	**4,818**			1,655	**17,552**
2023	1	Jan-23					511.0				1,675	
2023	2	Feb-23					425.9				1,553	
2023	3	Mar-23					424.2				1,577	
2023	4	Apr-23					360.1				1,478	
2023	5	May-23					396.0				1,366	
2023	6	Jun-23					333.1				1,315	
2023	7	Jul-23					323.2				1,404	
2023	8	Aug-23					355.7				1,279	
2023	9	Sep-23					315.5				1,272	
2023	10	Oct-23					389.9				1,421	
2023	11	Nov-23					453.6				1,597	
2023	12	Dec-23					442.1	**4,730**			1,655	**17,591**

Northland Utilities (NWT) Limited (Northland)
2023 Amended General Rate Application (GRA)
Fort Providence - Regression

FORT PROVIDENCE
Summary Output, Residential
Data: 2005:1 - 2019:12

Regression Statistics	
Multiple R	0.81927083
R Square	0.67120469
Adjusted R Square	0.66935752
Standard Error	42.5043593
Observations	180

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	656472.1572	656472.2	363.3702	7.37732E-45
Residual	178	321578.46	1806.621		
Total	179	978050.6173			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
INTERCEPT	340.830914	5.631136079	60.52614	1.1E-120	329.718538	351.9432906	329.718538	351.9432906
MHDD	0.14572182	0.007644515	19.06227	7.38E-45	0.130636284	0.160807362	0.130636284	0.160807362

Summary Output, Commercial
Data: 2005:1 - 2019:12

Regression Statistics	
Multiple R	0.66335964
R Square	0.44004601
Adjusted R Square	0.4369002
Standard Error	176.708491
Observations	180

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	4367979.346	4367979	139.8833	3.4428E-24
Residual	178	5558208.556	31225.89		
Total	179	9926187.902			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
INTERCEPT	1355.61216	23.41100006	57.90492	2.1E-117	1309.41334	1401.81098	1309.41334	1401.81098
MHDD	0.3758865	0.031781461	11.82723	3.44E-24	0.313169572	0.438603428	0.313169572	0.438603428

Northland Utilities (NWT) Limited (Northland)
2023 Amended General Rate Application (GRA)
Dory Point Kakisa - Data

Dory Point & Kakisa

Residential

Year	Month	monthly	MRCNT	MRENCNS (MWh)	UPC (kWh)	MHDD (Hay River)	UPC (kWh)	Annual UPC (kWh)
2005	1	Jan-05	21	12	576	1,260		
2005	2	Feb-05	21	8	395	1,034		
2005	3	Mar-05	21	8	384	949		
2005	4	Apr-05	21	11	523	542		
2005	5	May-05	21	10	464	407		
2005	6	Jun-05	21	9	447	209		
2005	7	Jul-05	21	9	413	86		
2005	8	Aug-05	21	8	392	143		
2005	9	Sep-05	21	11	512	308		
2005	10	Oct-05	21	10	474	474		
2005	11	Nov-05	21	11	527	767		
2005	12	Dec-05	21	13	596	866		**5,704**
2006	1	Jan-06	21	15	722	1,165		
2006	2	Feb-06	20	9	468	927		
2006	3	Mar-06	21	9	430	904		
2006	4	Apr-06	21	8	399	497		
2006	5	May-06	21	9	432	312		
2006	6	Jun-06	21	11	517	98		
2006	7	Jul-06	21	11	500	85		
2006	8	Aug-06	21	8	402	90		
2006	9	Sep-06	21	11	511	203		
2006	10	Oct-06	21	11	508	524		
2006	11	Nov-06	21	14	667	1,042		
2006	12	Dec-06	21	13	613	925		**6,169**
2007	1	Jan-07	21	12	575	1,108		
2007	2	Feb-07	23	11	494	1,168		
2007	3	Mar-07	23	10	427	1,100		
2007	4	Apr-07	23	10	445	560		
2007	5	May-07	24	12	485	368		
2007	6	Jun-07	25	9	371	161		
2007	7	Jul-07	24	9	391	38		
2007	8	Aug-07	24	9	369	187		
2007	9	Sep-07	24	10	427	366		
2007	10	Oct-07	24	10	418	489		
2007	11	Nov-07	24	14	564	850		
2007	12	Dec-07	24	12	486	1,188		**5,450**
2008	1	Jan-08	25	17	698	1,215		
2008	2	Feb-08	24	11	478	1,202		
2008	3	Mar-08	24	10	417	1,091		
2008	4	Apr-08	25	10	396	689		
2008	5	May-08	25	10	409	358		
2008	6	Jun-08	25	9	358	155		
2008	7	Jul-08	25	7	279	35		
2008	8	Aug-08	25	12	489	103		
2008	9	Sep-08	25	8	301	315		
2008	10	Oct-08	25	10	414	478		
2008	11	Nov-08	25	14	548	778		
2008	12	Dec-08	26	14	531	1,281		**5,318**
2009	1	Jan-09	26	16	610	1,238		
2009	2	Feb-09	26	10	373	1,085		
2009	3	Mar-09	26	9	347	1,116		
2009	4	Apr-09	26	10	399	623		
2009	5	May-09	26	10	366	490		
2009	6	Jun-09	26	9	344	193		
2009	7	Jul-09	26	10	395	101		
2009	8	Aug-09	26	9	350	88		
2009	9	Sep-09	26	9	348	177		
2009	10	Oct-09	26	11	418	560		
2009	11	Nov-09	26	12	477	825		
2009	12	Dec-09	26	13	481	1,163		**4,909**
2010	1	Jan-10	26	16	606	1,229		
2010	2	Feb-10	26	10	376	900		
2010	3	Mar-10	26	8	293	719		
2010	4	Apr-10	26	10	376	491		
2010	5	May-10	26	11	423	402		
2010	6	Jun-10	26	11	419	120		
2010	7	Jul-10	24	11	446	45		
2010	8	Aug-10	26	10	387	109		
2010	9	Sep-10	26	10	387	294		
2010	10	Oct-10	26	11	440	464		
2010	11	Nov-10	26	10	396	810		
2010	12	Dec-10	26	12	453	1,215		**5,003**
2011	1	Jan-11	26	14	523	1,289		
2011	2	Feb-11	26	12	478	1,007		
2011	3	Mar-11	26	9	361	1,041		
2011	4	Apr-11	26	9	338	720		
2011	5	May-11	26	10	403	361		
2011	6	Jun-11	26	10	400	168		
2011	7	Jul-11	25	9	373	37		
2011	8	Aug-11	26	9	350	86		
2011	9	Sep-11	26	9	359	206		
2011	10	Oct-11	26	10	382	471		
2011	11	Nov-11	26	10	396	952		

Commercial

MCCNT	MCENCNS (MWh)	UPC (kWh)	Annual UPC (kWh)
18	25	1,384	
18	17	931	
18	17	919	
17	17	1,027	
17	16	922	
22	13	583	
22	11	513	
23	11	479	
19	14	732	
17	14	800	
18	16	901	
19	18	944	**10,136**
19	22	1,175	
19	19	1,003	
18	15	834	
19	17	905	
19	12	643	
22	13	589	
19	12	636	
19	10	511	
20	14	704	
18	14	759	
20	26	1,307	
20	23	1,148	**10,212**
21	18	881	
18	21	1,190	
18	18	992	
20	15	727	
20	15	732	
20	11	528	
20	9	472	
20	10	482	
20	12	606	
18	14	795	
18	19	1,077	
19	19	1,024	**9,505**
24	25	1,053	
23	21	895	
23	25	1,087	
23	26	1,120	
26	21	814	
29	13	442	
29	8	278	
28	16	567	
28	17	610	
26	20	772	
22	30	1,386	
22	22	1,012	**10,036**
20	33	1,652	
21	53	2,520	
23	41	1,771	
25	27	1,084	
28	22	798	
27	14	523	
28	12	439	
28	14	486	
25	11	459	
28	17	622	
23	15	671	
20	16	786	**11,812**
20	30	1,504	
20	16	794	
19	13	706	
19	16	862	
22	17	770	
24	17	697	
24	12	519	
24	10	432	
24	11	456	
24	14	578	
19	16	816	
20	21	1,045	**9,177**
18	28	1,576	
20	31	1,550	
19	25	1,316	
19	24	1,237	
21	26	1,217	
24	19	782	
24	12	515	
24	10	426	
24	11	457	
19	11	577	
19	16	830	

Northland Utilities (NWT) Limited (Northland)
2023 Amended General Rate Application (GRA)
Dory Point Kakisa - Data

Dory Point & Kakisa

Residential

Year	Month	monthly	MRCNT	MRENCNS (MWh)	UPC (kWh)	MHDD (Hay River)	UPC (kWh)	Annual UPC (kWh)
2011	12	Dec-11	26	12	453	978		**4,815**
2012	1	Jan-12	26	14	537	1,184		
2012	2	Feb-12	26	12	459	913		
2012	3	Mar-12	26	10	388	992		
2012	4	Apr-12	26	9	347	676		
2012	5	May-12	26	10	378	277		
2012	6	Jun-12	26	10	378	156		
2012	7	Jul-12	26	10	374	13		
2012	8	Aug-12	26	11	434	60		
2012	9	Sep-12	26	9	359	178		
2012	10	Oct-12	26	10	387	575		
2012	11	Nov-12	26	11	423	1,011		
2012	12	Dec-12	26	11	429	1,328		**4,894**
2013	1	Jan-13	26	14	530	1,292		
2013	2	Feb-13	26	13	495	928		
2013	3	Mar-13	26	10	381	1,077		
2013	4	Apr-13	26	10	368	785		
2013	5	May-13	26	11	412	333		
2013	6	Jun-13	26	8	312	135		
2013	7	Jul-13	26	7	285	83		
2013	8	Aug-13	24	8	323	78		
2013	9	Sep-13	24	7	307	180		
2013	10	Oct-13	24	12	506	458		
2013	11	Nov-13	24	11	450	887		
2013	12	Dec-13	24	12	485	1,340		**4,852**
2014	1	Jan-14	24	11	449	1,200		
2014	2	Feb-14	24	11	459	1,188		
2014	3	Mar-14	24	7	287	1,121		
2014	4	Apr-14	24	8	325	691		
2014	5	May-14	24	7	278	380		
2014	6	Jun-14	24	8	328	158		
2014	7	Jul-14	25	9	354	35		
2014	8	Aug-14	24	8	314	104		
2014	9	Sep-14	24	7	312	274		
2014	10	Oct-14	24	10	429	521		
2014	11	Nov-14	24	8	326	910		
2014	12	Dec-14	24	8	344	1,144		**4,206**
2015	1	Jan-15	24	10	422	1,225		
2015	2	Feb-15	24	8	334	1,104		
2015	3	Mar-15	24	4	182	955		
2015	4	Apr-15	24	6	253	571		
2015	5	May-15	24	6	254	305		
2015	6	Jun-15	24	8	350	126		
2015	7	Jul-15	24	8	315	67		
2015	8	Aug-15	24	7	305	98		
2015	9	Sep-15	23	7	299	264		
2015	10	Oct-15	23	9	402	508		
2015	11	Nov-15	23	9	379	768		
2015	12	Dec-15	23	8	337	1,025		**3,832**
2016	1	Jan-16	23	10	424	1,087		
2016	2	Feb-16	23	7	306	1,050		
2016	3	Mar-16	23	9	385	925		
2016	4	Apr-16	23	6	278	683		
2016	5	May-16	23	7	304	312		
2016	6	Jun-16	23	1	51	105		
2016	7	Jul-16	23	17	740	47		
2016	8	Aug-16	23	8	351	79		
2016	9	Sep-16	23	8	335	250		
2016	10	Oct-16	23	12	517	566		
2016	11	Nov-16	23	7	299	722		
2016	12	Dec-16	23	4	177	1,191		**4,169**
2017	1	Jan-17	23	10	431	1,072		
2017	2	Feb-17	23	8	333	948		
2017	3	Mar-17	23	8	363	1,033		
2017	4	Apr-17	22	5	240	667		
2017	5	May-17	22	7	334	284		
2017	6	Jun-17	22	10	440	152		
2017	7	Jul-17	22	8	361	56		
2017	8	Aug-17	22	7	327	60		
2017	9	Sep-17	22	6	254	205		
2017	10	Oct-17	22	11	478	507		
2017	11	Nov-17	22	6	277	976		
2017	12	Dec-17	22	7	328	1,084		**4,165**
2018	1	Jan-18	21	10	459	1,265		
2018	2	Feb-18	21	8	372	1,044		
2018	3	Mar-18	20	4	221	992		
2018	4	Apr-18	20	7	345	723		
2018	5	May-18	20	5	272	327		
2018	6	Jun-18	20	13	647	157		
2018	7	Jul-18	20	4	224	74		
2018	8	Aug-18	20	6	294	119		
2018	9	Sep-18	20	4	198	425		
2018	10	Oct-18	19	11	565	566		

Commercial

MCCNT	MCENCNS (MWh)	UPC (kWh)	Annual UPC (kWh)
19	19	1,022	**11,505**
19	26	1,343	
19	24	1,238	
19	22	1,167	
19	22	1,152	
21	23	1,072	
24	17	714	
24	13	522	
24	13	538	
25	11	435	
20	11	557	
20	17	825	
20	18	916	**10,479**
20	24	1,200	
19	19	1,021	
19	16	830	
19	15	785	
25	15	584	
25	12	488	
25	9	368	
24	9	367	
24	9	378	
24	13	521	
24	17	697	
18	21	1,156	**8,396**
18	21	1,189	
18	16	902	
18	17	948	
18	13	734	
19	12	634	
23	10	416	
23	7	304	
23	9	402	
23	9	399	
19	10	528	
20	16	812	
20	20	1,014	**8,283**
19	23	1,205	
19	28	1,451	
19	25	1,309	
19	15	799	
20	12	607	
23	8	331	
23	6	282	
24	9	387	
24	11	469	
19	10	537	
19	13	681	
18	16	908	**8,966**
18	18	1,013	
18	17	934	
18	14	792	
18	15	830	
17	13	762	
22	-4	(201)	
22	21	964	
22	9	422	
22	11	479	
17	10	572	
17	17	1,021	
17	15	880	**8,468**
17	18	1,072	
17	15	897	
17	16	934	
17	12	724	
17	11	663	
22	7	296	
22	9	399	
22	10	459	
22	11	520	
17	10	604	
17	19	1,121	
17	15	897	**8,586**
17	19	1,107	
17	16	915	
17	17	978	
17	15	871	
19	13	664	
21	3	125	
22	13	578	
22	9	413	
21	12	572	
16	6	396	

Northland Utilities (NWT) Limited (Northland)
2023 Amended General Rate Application (GRA)
Dory Point Kakisa - Data

Dory Point & Kakisa

Residential

Year	Month	monthly	MRCNT	MRENCNS (MWh)	UPC (kWh)	MHDD (Hay River)	UPC (kWh)	Annual UPC (kWh)
2018	11	Nov-18	19	10	552	880		
2018	12	Dec-18	18	2	117	1,046		**4,267**
2019	1	Jan-19	18	8	428	1,223		
2019	2	Feb-19	18	10	548	1,153		
2019	3	Mar-19	18	6	315	710		
2019	4	Apr-19	18	5	300	567		
2019	5	May-19	18	9	514	433		
2019	6	Jun-19	18	8	454	196		
2019	7	Jul-19	19	9	467	100		
2019	8	Aug-19	19	12	625	153		
2019	9	Sep-19	19	7	356	265		
2019	10	Oct-19	19	7	356	516		
2019	11	Nov-19	19	5	285	849		
2019	12	Dec-19	19	5	255	1,227		**4,903**
2020	1	Jan-20	19	11	587	1,289		
2020	2	Feb-20	19	8	406	1,106		
2020	3	Mar-20	19	8	431	1,078		
2020	4	Apr-20	19	9	462	734		
2020	5	May-20	19	6	316	460		
2020	6	Jun-20	19	10	550	207		
2020	7	Jul-20	19	6	304	76		
2020	8	Aug-20	19	10	506	116		
2020	9	Sep-20	19	4	216	273		
2020	10	Oct-20	20	10	523	586		
2020	11	Nov-20	20	9	469	927		
2020	12	Dec-20	21	8	363	1,077		**5,133**
2021	1	Jan-21	20	11	559	1,099		
2021	2	Feb-21	20	7	365	1,227		
2021	3	Mar-21	20	8	404	1,031		
2021	4	Apr-21	20	6	319	698		
2021	5	May-21	20	6	305	403		
2021	6	Jun-21	20	11	544	146		
2021	7	Jul-21	21	7	344	64		
2021	8	Aug-21	21	7	311	118		
2021	9	Sep-21	21	16	762	233		
2021	10	Oct-21	21	3	122	458		
2021	11	Nov-21	21	6	273	822		
2021	12	Dec-21	21	9	437	1,337		**4,745**
2022	1	Jan-22	21	14	650	1,263	650	
2022	2	Feb-22	21	10	480	1,200	480	
2022	3	Mar-22	21	7	352	1,047	352	
2022	4	Apr-22	21	4	203	707	203	
2022	5	May-22	21	8	392	393	392	
2022	6	Jun-22			454		454	
2022	7	Jul-22			467		467	
2022	8	Aug-22			625		625	
2022	9	Sep-22			356		356	
2022	10	Oct-22			356		356	
2022	11	Nov-22			285		285	
2022	12	Dec-22			255		255	**4,876**
2023	1	Jan-23			428		428	
2023	2	Feb-23			548		548	
2023	3	Mar-23			315		315	
2023	4	Apr-23			300		300	
2023	5	May-23			514		514	
2023	6	Jun-23			454		454	
2023	7	Jul-23			467		467	
2023	8	Aug-23			625		625	
2023	9	Sep-23			356		356	
2023	10	Oct-23			356		356	
2023	11	Nov-23			285		285	
2023	12	Dec-23			255		255	**4,903**

Commercial

MCCNT	MCENCNS (MWh)	UPC (kWh)	Annual UPC (kWh)
16	20	1,257	
16	10	653	**8,530**
16	15	942	
16	10	609	
16	13	801	
16	11	702	
20	8	423	
20	6	316	
21	5	250	
20	3	171	
21	19	581	
16	-1	402	
14	13	1,277	
14	16	664	**7,137**
14	12	865	
14	12	843	
14	11	776	
14	9	662	
14	11	762	
14	4	307	
19	9	454	
19	6	310	
19	12	615	
19	7	355	
14	9	658	
14	16	1,109	**7,715**
14	9	676	
14	13	940	
12	10	866	
12	12	980	
14	10	749	
19	4	226	
19	9	447	
19	9	449	
19	-1	(45)	
13	14	1,102	
14	12	870	
14	17	1,242	**8,502**
13	13	1,010	
14	13	950	
14	13	918	
14	13	930	
14	10	725	
		316	
		250	
		171	
		581	
		402	
		1,277	
		664	**8,194**
		942	
		609	
		801	
		702	
		423	
		316	
		250	
		171	
		581	
		402	
		1,277	
		664	**7,137**

Northland Utilities (NWT) Limited (Northland)
2023 Amended General Rate Application (GRA)
Dory Point Kakisa Regression

DORY POINT & KAKISA
Summary Output, Residential
Data: 2005:1 - 2019:12

Regression Statistics	
Multiple R	0.227066
R Square	0.051559
Adjusted R Square	0.046231
Standard Error	104.75
Observations	180

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	106175.0018	106175	9.676401	0.002174317
Residual	178	1953117.817	10972.57		
Total	179	2059292.819			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
INTERCEPT	367.9571	13.87767676	26.51431	1.02E-63	340.5711111	395.3429953	340.5711111	395.3429953
MHDD	0.058604	0.018839556	3.110691	0.002174	0.021426424	0.095781662	0.021426424	0.095781662

Summary Output, Commercial
Data: 2005:1 - 2019:12

Regression Statistics	
Multiple R	0.73888
R Square	0.545944
Adjusted R Square	0.543393
Standard Error	238.5921
Observations	180

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	12183450.07	12183450	214.0219	2.44524E-32
Residual	178	10132859.78	56926.18		
Total	179	22316309.85			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
INTERCEPT	402.2924	31.6095682	12.72692	8.38E-27	339.9146563	464.6700918	339.9146563	464.6700918
MHDD	0.627771	0.042911377	14.62949	2.45E-32	0.543090991	0.712451976	0.543090991	0.712451976

Northland Utilities (NWT) Limited (Northland)
2023 Amended General Rate Application (GRA)
Sambaa K'e - Data

Sambaa K'e

Residential

Year	Month	monthly	MRCNT	MRENCNS (MWh)	UPC (kWh)	MHDD (Hay River)	UPC (kWh)	Annual UPC (kWh)
2005	1	Jan-05	33	20	605	1,260		
2005	2	Feb-05	33	14	428	1,034		
2005	3	Mar-05	32	13	394	949		
2005	4	Apr-05	32	15	460	542		
2005	5	May-05	32	12	377	407		
2005	6	Jun-05	32	11	348	209		
2005	7	Jul-05	34	12	348	86		
2005	8	Aug-05	33	14	426	143		
2005	9	Sep-05	34	11	332	308		
2005	10	Oct-05	35	13	371	474		
2005	11	Nov-05	33	14	420	767		
2005	12	Dec-05	33	16	479	866		**4,986**
2006	1	Jan-06	33	21	632	1,165		
2006	2	Feb-06	33	13	385	927		
2006	3	Mar-06	33	13	408	904		
2006	4	Apr-06	33	15	440	497		
2006	5	May-06	33	12	359	312		
2006	6	Jun-06	34	13	389	98		
2006	7	Jul-06	35	14	394	85		
2006	8	Aug-06	35	16	454	90		
2006	9	Sep-06	34	9	267	203		
2006	10	Oct-06	35	12	354	524		
2006	11	Nov-06	34	15	432	1,042		
2006	12	Dec-06	36	18	501	925		**5,014**
2007	1	Jan-07	38	19	497	1,108		
2007	2	Feb-07	36	15	420	1,168		
2007	3	Mar-07	36	16	441	1,100		
2007	4	Apr-07	36	16	456	560		
2007	5	May-07	36	12	331	368		
2007	6	Jun-07	36	13	355	161		
2007	7	Jul-07	42	13	321	38		
2007	8	Aug-07	38	14	364	187		
2007	9	Sep-07	39	15	379	366		
2007	10	Oct-07	40	14	344	489		
2007	11	Nov-07	39	18	454	850		
2007	12	Dec-07	39	18	468	1,188		**4,829**
2008	1	Jan-08	39	19	482	1,215		
2008	2	Feb-08	41	20	487	1,202		
2008	3	Mar-08	43	23	530	1,091		
2008	4	Apr-08	41	15	369	689		
2008	5	May-08	42	13	305	358		
2008	6	Jun-08	41	12	288	155		
2008	7	Jul-08	41	13	323	35		
2008	8	Aug-08	41	17	409	103		
2008	9	Sep-08	40	16	408	315		
2008	10	Oct-08	40	14	339	478		
2008	11	Nov-08	40	17	421	778		
2008	12	Dec-08	41	18	428	1,281		**4,790**
2009	1	Jan-09	41	20	496	1,238		
2009	2	Feb-09	40	22	550	1,085		
2009	3	Mar-09	41	17	420	1,116		
2009	4	Apr-09	42	17	397	623		
2009	5	May-09	42	18	431	490		
2009	6	Jun-09	42	15	348	193		
2009	7	Jul-09	42	16	382	101		
2009	8	Aug-09	42	13	298	88		
2009	9	Sep-09	42	14	329	177		
2009	10	Oct-09	42	16	379	560		
2009	11	Nov-09	42	21	493	825		
2009	12	Dec-09	42	16	387	1,163		**4,909**
2010	1	Jan-10	42	23	546	1,229		
2010	2	Feb-10	42	17	408	900		
2010	3	Mar-10	43	17	387	719		
2010	4	Apr-10	42	18	431	491		
2010	5	May-10	42	13	304	402		
2010	6	Jun-10	41	13	325	120		
2010	7	Jul-10	42	16	389	45		
2010	8	Aug-10	43	13	301	109		
2010	9	Sep-10	43	13	291	294		
2010	10	Oct-10	43	16	377	464		
2010	11	Nov-10	43	18	409	810		
2010	12	Dec-10	43	19	451	1,215		**4,620**
2011	1	Jan-11	43	22	509	1,289		
2011	2	Feb-11	44	23	530	1,007		
2011	3	Mar-11	44	17	396	1,041		
2011	4	Apr-11	43	22	518	720		
2011	5	May-11	43	16	362	361		
2011	6	Jun-11	43	15	355	168		
2011	7	Jul-11	43	16	382	37		
2011	8	Aug-11	43	11	266	86		
2011	9	Sep-11	43	16	361	206		
2011	10	Oct-11	43	13	305	471		
2011	11	Nov-11	43	14	334	952		

Commercial

MCCNT	MCENCNS (MWh)	UPC (kWh)	Annual UPC (kWh)
15	21	1,417	
15	16	1,062	
15	14	929	
15	14	963	
15	11	759	
15	12	811	
15	12	782	
15	11	719	
16	9	586	
16	10	634	
16	14	856	
15	17	1,101	**10,621**
15	20	1,302	
15	13	842	
15	15	1,022	
15	15	971	
19	13	660	
14	15	1,045	
15	15	984	
14	13	932	
14	10	679	
14	11	760	
14	15	1,040	
15	17	1,134	**11,370**
15	17	1,148	
16	20	1,269	
17	15	907	
16	22	1,350	
16	14	878	
16	16	1,003	
16	19	1,200	
16	12	769	
16	16	985	
16	13	826	
16	17	1,042	
16	20	1,236	**12,612**
16	19	1,184	
16	16	1,013	
16	27	1,671	
16	9	581	
16	13	802	
16	11	693	
16	13	836	
16	23	1,423	
16	18	1,101	
16	15	956	
16	17	1,069	
16	16	998	**12,326**
16	18	1,130	
16	22	1,349	
16	16	1,027	
15	19	1,251	
16	18	1,131	
16	17	1,045	
16	18	1,147	
16	13	823	
16	16	1,016	
16	17	1,051	
16	21	1,322	
16	19	1,158	**13,450**
16	25	1,593	
15	18	1,222	
16	20	1,226	
17	22	1,275	
17	16	953	
17	17	1,017	
17	22	1,318	
17	16	945	
17	16	932	
17	20	1,159	
17	21	1,262	
17	23	1,327	**14,230**
17	26	1,515	
17	23	1,357	
17	20	1,184	
17	23	1,379	
17	18	1,041	
17	16	966	
17	18	1,051	
17	15	869	
17	18	1,085	
17	14	831	
17	15	906	

Northland Utilities (NWT) Limited (Northland)
2023 Amended General Rate Application (GRA)
Sambaa K'e - Data

Sambaa K'e

Residential

Year	Month	monthly	MRCNT	MRENCNS (MWh)	UPC (kWh)	MHDD (Hay River)	UPC (kWh)	Annual UPC (kWh)
2011	12	Dec-11	43	19	438	978		**4,756**
2012	1	Jan-12	43	21	494	1,184		
2012	2	Feb-12	43	22	514	913		
2012	3	Mar-12	43	17	397	992		
2012	4	Apr-12	43	18	424	676		
2012	5	May-12	43	16	364	277		
2012	6	Jun-12	43	18	422	156		
2012	7	Jul-12	44	14	310	13		
2012	8	Aug-12	42	13	318	60		
2012	9	Sep-12	44	16	370	178		
2012	10	Oct-12	44	12	268	575		
2012	11	Nov-12	44	19	439	1,011		
2012	12	Dec-12	44	22	502	1,328		**4,822**
2013	1	Jan-13	44	21	479	1,292		
2013	2	Feb-13	44	22	507	928		
2013	3	Mar-13	44	20	454	1,077		
2013	4	Apr-13	45	20	435	785		
2013	5	May-13	45	14	306	333		
2013	6	Jun-13	45	17	369	135		
2013	7	Jul-13	45	17	371	83		
2013	8	Aug-13	44	15	340	78		
2013	9	Sep-13	44	19	424	180		
2013	10	Oct-13	44	17	384	458		
2013	11	Nov-13	43	19	435	887		
2013	12	Dec-13	44	21	488	1,340		**4,993**
2014	1	Jan-14	44	21	483	1,200		
2014	2	Feb-14	44	18	418	1,188		
2014	3	Mar-14	44	19	422	1,121		
2014	4	Apr-14	44	16	364	691		
2014	5	May-14	44	15	346	380		
2014	6	Jun-14	42	14	337	158		
2014	7	Jul-14	43	18	421	35		
2014	8	Aug-14	42	17	416	104		
2014	9	Sep-14	42	14	322	274		
2014	10	Oct-14	42	18	424	521		
2014	11	Nov-14	42	19	454	910		
2014	12	Dec-14	42	22	515	1,144		**4,922**
2015	1	Jan-15	42	23	550	1,225		
2015	2	Feb-15	42	17	409	1,104		
2015	3	Mar-15	43	23	543	955		
2015	4	Apr-15	43	8	182	571		
2015	5	May-15	43	15	342	305		
2015	6	Jun-15	43	14	333	126		
2015	7	Jul-15	43	15	350	67		
2015	8	Aug-15	42	15	348	98		
2015	9	Sep-15	43	16	367	264		
2015	10	Oct-15	43	17	391	508		
2015	11	Nov-15	43	19	431	768		
2015	12	Dec-15	43	18	429	1,025		**4,677**
2016	1	Jan-16	43	21	486	1,087		
2016	2	Feb-16	42	17	397	1,050		
2016	3	Mar-16	42	16	376	925		
2016	4	Apr-16	42	16	389	683		
2016	5	May-16	42	15	355	312		
2016	6	Jun-16	42	14	339	105		
2016	7	Jul-16	42	14	330	47		
2016	8	Aug-16	42	15	349	79		
2016	9	Sep-16	42	13	308	250		
2016	10	Oct-16	41	18	437	566		
2016	11	Nov-16	42	15	362	722		
2016	12	Dec-16	42	17	405	1,191		**4,533**
2017	1	Jan-17	42	18	440	1,072		
2017	2	Feb-17	42	15	361	948		
2017	3	Mar-17	42	17	402	1,033		
2017	4	Apr-17	42	13	306	667		
2017	5	May-17	42	15	369	284		
2017	6	Jun-17	42	14	341	152		
2017	7	Jul-17	42	15	366	56		
2017	8	Aug-17	42	15	361	60		
2017	9	Sep-17	42	13	318	205		
2017	10	Oct-17	41	15	365	507		
2017	11	Nov-17	41	17	410	976		
2017	12	Dec-17	41	16	385	1,084		**4,425**
2018	1	Jan-18	41	20	490	1,265		
2018	2	Feb-18	41	15	365	1,044		
2018	3	Mar-18	41	17	406	992		
2018	4	Apr-18	41	18	442	723		
2018	5	May-18	41	16	390	327		
2018	6	Jun-18	41	16	386	157		
2018	7	Jul-18	41	18	443	74		
2018	8	Aug-18	41	18	437	119		
2018	9	Sep-18	41	18	436	425		
2018	10	Oct-18	41	18	428	566		

Commercial

MCCNT	MCENCNS (MWh)	UPC (kWh)	Annual UPC (kWh)
15	17	1,146	**13,331**
16	22	1,355	
16	19	1,176	
15	17	1,129	
15	18	1,208	
15	17	1,102	
15	18	1,225	
16	16	978	
16	15	941	
16	19	1,166	
16	14	891	
15	22	1,454	
15	25	1,674	**14,298**
15	22	1,439	
15	23	1,565	
16	33	2,087	
15	24	1,598	
15	18	1,174	
16	19	1,181	
16	18	1,141	
16	17	1,052	
16	21	1,326	
16	20	1,234	
16	20	1,254	
17	25	1,467	**16,519**
17	22	1,291	
17	21	1,225	
17	20	1,192	
17	18	1,076	
17	17	1,014	
16	17	1,087	
16	18	1,113	
16	14	898	
17	18	1,082	
17	19	1,103	
17	21	1,234	
17	25	1,491	**13,806**
17	25	1,448	
17	23	1,345	
16	26	1,638	
16	12	755	
16	17	1,050	
16	17	1,051	
16	16	1,003	
16	16	1,028	
16	17	1,054	
16	18	1,147	
15	18	1,219	
16	23	1,454	**14,192**
16	23	1,461	
16	19	1,177	
16	18	1,105	
16	18	1,108	
16	15	957	
16	14	857	
16	13	840	
15	15	970	
16	15	965	
16	16	1,003	
16	21	1,304	
16	22	1,390	**13,137**
16	21	1,310	
16	20	1,234	
16	22	1,392	
16	17	1,060	
16	19	1,184	
16	16	973	
16	16	1,004	
16	16	982	
16	15	944	
16	18	1,145	
16	20	1,252	
16	24	1,522	**14,002**
16	21	1,322	
16	22	1,347	
16	19	1,201	
16	20	1,238	
16	19	1,179	
17	17	1,001	
17	17	1,004	
17	16	968	
17	16	945	
17	25	1,455	

Northland Utilities (NWT) Limited (Northland)
2023 Amended General Rate Application (GRA)
Sambaa K'e - Data

Sambaa K'e

Residential

Year	Month	monthly	MRCNT	MRENCNS (MWh)	UPC (kWh)	MHDD (Hay River)	UPC (kWh)	Annual UPC (kWh)
2018	11	Nov-18	41	11	260	880		
2018	12	Dec-18	41	28	678	1,046		**5,159**
2019	1	Jan-19	41	20	498	1,223		
2019	2	Feb-19	40	24	598	1,153		
2019	3	Mar-19	41	13	321	710		
2019	4	Apr-19	41	15	373	567		
2019	5	May-19	41	15	370	433		
2019	6	Jun-19	41	16	379	196		
2019	7	Jul-19	37	15	404	100		
2019	8	Aug-19	38	14	369	153		
2019	9	Sep-19	38	13	341	265		
2019	10	Oct-19	38	13	341	516		
2019	11	Nov-19	38	21	543	849		
2019	12	Dec-19	38	21	547	1,227		**5,086**
2020	1	Jan-20	38	22	578	1,289		
2020	2	Feb-20	38	18	473	1,106		
2020	3	Mar-20	39	17	448	1,078		
2020	4	Apr-20	39	16	408	734		
2020	5	May-20	40	16	404	460		
2020	6	Jun-20	40	16	390	207		
2020	7	Jul-20	40	18	443	76		
2020	8	Aug-20	41	14	342	116		
2020	9	Sep-20	41	19	462	273		
2020	10	Oct-20	41	17	414	586		
2020	11	Nov-20	41	19	459	927		
2020	12	Dec-20	41	26	642	1,077		**5,463**
2021	1	Jan-21	41	22	532	1,099		
2021	2	Feb-21	41	20	479	1,227		
2021	3	Mar-21	40	13	315	1,031		
2021	4	Apr-21	41	18	427	698		
2021	5	May-21	41	15	358	403		
2021	6	Jun-21	41	16	380	146		
2021	7	Jul-21	40	14	340	64		
2021	8	Aug-21	40	14	355	118		
2021	9	Sep-21	40	16	410	233		
2021	10	Oct-21	40	16	405	458		
2021	11	Nov-21	40	19	464	822		
2021	12	Dec-21	40	19	473	1,337		**4,938**
2022	1	Jan-22	40	24	601	1,263	601	
2022	2	Feb-22	40	15	366	1,200	366	
2022	3	Mar-22	39	17	445	1,047	445	
2022	4	Apr-22	40	15	384	707	384	
2022	5	May-22	40	11	275	393	275	
2022	6	Jun-22			369		369	
2022	7	Jul-22			404		404	
2022	8	Aug-22			389		389	
2022	9	Sep-22			365		365	
2022	10	Oct-22			378		378	
2022	11	Nov-22			404		404	
2022	12	Dec-22			536		536	**4,918**
2023	1	Jan-23			476		476	
2023	2	Feb-23			441		441	
2023	3	Mar-23			376		376	
2023	4	Apr-23			374		374	
2023	5	May-23			376		376	
2023	6	Jun-23			369		369	
2023	7	Jul-23			404		404	
2023	8	Aug-23			389		389	
2023	9	Sep-23			365		365	
2023	10	Oct-23			378		378	
2023	11	Nov-23			404		404	
2023	12	Dec-23			536		536	**4,890**

Commercial

MCCNT	MCENCNS (MWh)	UPC (kWh)	Annual UPC (kWh)
17	13	775	
17	32	1,898	**14,333**
18	28	1,557	
16	20	1,222	
18	22	1,202	
17	14	829	
17	16	941	
17	14	804	
17	13	791	
16	12	772	
16	9	585	
16	16	1,029	
16	16	1,026	
16	16	1,001	**11,757**
16	19	1,197	
16	16	987	
16	17	1,060	
16	14	864	
16	13	827	
16	12	747	
16	14	874	
16	15	931	
17	14	821	
17	16	955	
17	18	1,075	
16	13	825	**11,162**
16	20	1,231	
16	19	1,178	
17	22	1,287	
17	13	747	
17	16	939	
17	13	771	
17	15	865	
17	14	849	
17	13	746	
17	18	1,036	
17	17	1,009	
17	23	1,359	**12,017**
16	18	1,121	
17	23	1,368	
17	17	1,023	
15	17	1,119	
17	19	1,137	
		804	
		791	
		772	
		585	
		1,029	
		1,026	
		1,001	**11,774**
		1,557	
		1,222	
		1,202	
		829	
		941	
		804	
		791	
		772	
		585	
		1,029	
		1,026	
		1,001	**11,757**

Northland Utilities (NWT) Limited (Northland)
2023 Amended General Rate Application (GRA)
Sambaa K'e - Regression

Sambaa K'e

Summary Output, Residential

Data: 2005:1 - 2019:12

Regression Statistics	
Multiple R	0.637574864
R Square	0.406501708
Adjusted R Square	0.403167448
Standard Error	57.90991231
Observations	180

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	408854.4395	408854.4	121.9166	6.34552E-22
Residual	178	596933.314	3353.558		
Total	179	1005787.753			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
INTERCEPT	332.8616019	7.672121205	43.38586	1.39E-96	317.7215845	348.0016192	317.7215845	348.0016192
MHDD	0.115000783	0.010415242	11.04159	6.35E-22	0.094447545	0.135554022	0.094447545	0.135554022

Summary Output, Commercial

Data: 2005:1 - 2019:12

Regression Statistics	
Multiple R	0.559613874
R Square	0.313167688
Adjusted R Square	0.30930908
Standard Error	204.7802085
Observations	180

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	3403472.081	3403472	81.16078	3.18276E-16
Residual	178	7464418.215	41934.93		
Total	179	10867890.3			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
INTERCEPT	908.9651334	27.13004592	33.504	8.68E-79	855.4272192	962.5030475	855.4272192	962.5030475
MHDD	0.331800882	0.036830229	9.008928	3.18E-16	0.259120812	0.404480952	0.259120812	0.404480952

Northland Utilities (NWT) Limited (Northland)
2023 Amended General Rate Application (GRA)
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Wekweeti

Residential

Year	Month	monthly	MRCNT	MRENCNS (MWh)	MRUPC (kWh)	MHDD (Yellowknife)	UPC (kWh)	Annual UPC (kWh)
2005	1	Jan-05	38	23	605	1,376		
2005	2	Feb-05	41	24	586	1,140		
2005	3	Mar-05	45	21	477	1,027		
2005	4	Apr-05	43	23	534	613		
2005	5	May-05	41	22	535	459		
2005	6	Jun-05	42	19	444	165		
2005	7	Jul-05	43	20	454	84		
2005	8	Aug-05	43	18	414	155		
2005	9	Sep-05	44	20	462	364		
2005	10	Oct-05	42	21	492	547		
2005	11	Nov-05	43	20	460	812		
2005	12	Dec-05	44	28	633	967		**6,095**
2006	1	Jan-06	43	23	545	1,239		
2006	2	Feb-06	43	21	498	994		
2006	3	Mar-06	43	20	468	896		
2006	4	Apr-06	43	23	534	597		
2006	5	May-06	43	20	474	307		
2006	6	Jun-06	43	20	469	81		
2006	7	Jul-06	44	18	402	59		
2006	8	Aug-06	43	19	433	85		
2006	9	Sep-06	42	19	461	244		
2006	10	Oct-06	42	20	478	582		
2006	11	Nov-06	42	20	482	1,063		
2006	12	Dec-06	42	31	729	1,015		**5,971**
2007	1	Jan-07	42	19	449	1,221		
2007	2	Feb-07	42	25	594	1,205		
2007	3	Mar-07	42	17	415	1,180		
2007	4	Apr-07	41	21	506	629		
2007	5	May-07	41	17	407	386		
2007	6	Jun-07	41	18	433	149		
2007	7	Jul-07	42	17	396	20		
2007	8	Aug-07	42	13	298	181		
2007	9	Sep-07	43	16	364	392		
2007	10	Oct-07	42	18	419	562		
2007	11	Nov-07	43	23	531	908		
2007	12	Dec-07	42	22	522	1,306		**5,336**
2008	1	Jan-08	42	24	568	1,365		
2008	2	Feb-08	41	25	603	1,297		
2008	3	Mar-08	42	25	599	1,184		
2008	4	Apr-08	41	18	451	761		
2008	5	May-08	41	18	445	335		
2008	6	Jun-08	41	18	450	133		
2008	7	Jul-08	41	17	407	33		
2008	8	Aug-08	41	15	360	115		
2008	9	Sep-08	40	17	429	369		
2008	10	Oct-08	40	17	425	518		
2008	11	Nov-08	40	22	544	827		
2008	12	Dec-08	40	20	497	1,420		**5,778**
2009	1	Jan-09	39	24	614	1,353		
2009	2	Feb-09	39	24	625	1,161		
2009	3	Mar-09	40	19	469	1,188		
2009	4	Apr-09	37	22	598	691		
2009	5	May-09	40	19	467	516		
2009	6	Jun-09	39	17	433	175		
2009	7	Jul-09	39	17	446	80		
2009	8	Aug-09	38	16	414	102		
2009	9	Sep-09	40	15	376	227		
2009	10	Oct-09	40	17	430	603		
2009	11	Nov-09	40	23	567	867		
2009	12	Dec-09	40	21	526	1,238		**5,965**
2010	1	Jan-10	38	26	671	1,307		
2010	2	Feb-10	40	23	564	960		
2010	3	Mar-10	40	21	524	866		
2010	4	Apr-10	40	22	553	515		
2010	5	May-10	40	17	426	384		
2010	6	Jun-10	40	18	462	109		
2010	7	Jul-10	40	18	449	40		
2010	8	Aug-10	39	19	485	90		
2010	9	Sep-10	40	20	494	308		
2010	10	Oct-10	40	16	389	544		
2010	11	Nov-10	39	22	562	899		
2010	12	Dec-10	39	23	591	1,238		**6,168**
2011	1	Jan-11	40	26	652	1,394		
2011	2	Feb-11	40	27	687	1,140		
2011	3	Mar-11	40	22	557	1,109		
2011	4	Apr-11	40	23	570	817		
2011	5	May-11	40	21	523	327		
2011	6	Jun-11	39	19	488	148		
2011	7	Jul-11	40	19	467	26		
2011	8	Aug-11	40	15	378	88		
2011	9	Sep-11	40	16	408	242		
2011	10	Oct-11	40	19	469	514		
2011	11	Nov-11	40	19	482	985		

Commercial

MCCNT	MCENCNS (MWh)	MCUPC (kWh)	Annual UPC (kWh)
16	30	1,857	
15	29	1,923	
14	29	2,063	
14	31	2,181	
14	26	1,854	
14	23	1,608	
14	22	1,573	
14	18	1,293	
14	23	1,654	
14	22	1,600	
14	24	1,744	
14	39	2,761	**22,109**
14	29	2,066	
14	27	1,905	
14	27	1,935	
14	28	1,997	
14	30	2,142	
14	24	1,687	
14	15	1,056	
14	17	1,179	
15	22	1,460	
15	24	1,569	
15	26	1,702	
15	40	2,686	**21,384**
15	30	2,019	
15	28	1,850	
15	37	2,473	
15	25	1,644	
15	25	1,674	
15	26	1,766	
15	23	1,511	
15	19	1,277	
15	21	1,401	
15	22	1,498	
15	31	2,060	
15	33	2,213	**21,386**
15	36	2,418	
15	32	2,145	
15	35	2,358	
15	32	2,118	
15	26	1,735	
15	23	1,552	
15	21	1,395	
15	20	1,337	
15	22	1,481	
17	23	1,324	
16	28	1,750	
16	28	1,734	**21,346**
15	33	2,181	
14	28	2,007	
16	33	2,087	
12	25	2,120	
16	36	2,250	
16	25	1,567	
16	18	1,132	
16	17	1,054	
17	22	1,271	
17	24	1,407	
17	33	1,933	
17	36	2,113	**21,122**
17	36	2,090	
17	33	1,932	
16	22	1,405	
17	43	2,515	
17	23	1,342	
17	23	1,342	
17	21	1,238	
15	15	985	
17	27	1,596	
17	22	1,283	
16	22	1,391	
17	30	1,768	**18,887**
17	35	2,054	
18	34	1,906	
18	34	1,916	
18	29	1,594	
18	29	1,597	
17	21	1,264	
18	22	1,248	
18	21	1,144	
18	18	1,001	
17	27	1,608	
18	27	1,477	

Northland Utilities (NWT) Limited (Northland)
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Wekweeti

			Residential						Commercial			
			MRCNT	MRENCNS	MRUPC	MHDD	UPC	Annual	MCCNT	MCENCNS	MCUPC	Annual
Year	Month	monthly		(MWh)	(kWh)	(Yellowknife)	(kWh)	UPC (kWh)		(MWh)	(kWh)	UPC (kWh)
2011	12	Dec-11	41	24	586	1,100		**6,268**	18	31	1,716	**18,525**
2012	1	Jan-12	41	29	699	1,252			18	38	2,107	
2012	2	Feb-12	41	22	533	1,013			17	25	1,466	
2012	3	Mar-12	41	20	496	1,059			18	35	1,933	
2012	4	Apr-12	41	19	462	723			18	33	1,810	
2012	5	May-12	41	18	440	311			18	26	1,434	
2012	6	Jun-12	41	18	439	79			19	25	1,329	
2012	7	Jul-12	41	18	447	7			19	21	1,089	
2012	8	Aug-12	41	19	465	64			19	21	1,117	
2012	9	Sep-12	40	18	449	203			19	18	929	
2012	10	Oct-12	41	18	440	601			19	26	1,355	
2012	11	Nov-12	41	23	564	1,066			19	29	1,552	
2012	12	Dec-12	41	27	653	1,402		**6,087**	19	37	1,931	**18,052**
2013	1	Jan-13	41	32	775	1,428			19	42	2,222	
2013	2	Feb-13	41	31	745	1,035			18	37	2,033	
2013	3	Mar-13	41	22	526	1,128			19	36	1,881	
2013	4	Apr-13	41	20	491	809			19	31	1,615	
2013	5	May-13	41	20	497	353			19	30	1,585	
2013	6	Jun-13	41	21	517	105			19	29	1,547	
2013	7	Jul-13	41	18	434	80			19	23	1,188	
2013	8	Aug-13	41	18	434	99			19	22	1,180	
2013	9	Sep-13	41	18	439	245			19	19	990	
2013	10	Oct-13	41	25	599	518			19	26	1,363	
2013	11	Nov-13	41	26	639	963			19	32	1,665	
2013	12	Dec-13	41	28	678	1,501		**6,774**	18	39	2,189	**19,458**
2014	1	Jan-14	41	26	646	1,343			19	34	1,805	
2014	2	Feb-14	41	28	683	1,234			19	32	1,664	
2014	3	Mar-14	40	23	569	1,192			19	33	1,743	
2014	4	Apr-14	40	19	482	769			19	29	1,536	
2014	5	May-14	40	19	477	408			19	27	1,430	
2014	6	Jun-14	40	18	461	114			19	19	1,010	
2014	7	Jul-14	38	16	409	40			19	23	1,193	
2014	8	Aug-14	39	21	541	136			17	18	1,051	
2014	9	Sep-14	39	11	286	346			19	32	1,674	
2014	10	Oct-14	39	25	645	559			19	24	1,248	
2014	11	Nov-14	39	19	488	1,036			19	39	2,058	
2014	12	Dec-14	39	25	635	1,213		**6,321**	19	41	2,182	**18,595**
2015	1	Jan-15	39	22	564	1,340			19	40	2,087	
2015	2	Feb-15	39	26	673	1,230			19	38	2,010	
2015	3	Mar-15	39	21	527	1,039			19	37	1,946	
2015	4	Apr-15	39	18	453	661			19	36	1,889	
2015	5	May-15	39	18	464	323			19	29	1,541	
2015	6	Jun-15	39	17	436	114			19	23	1,185	
2015	7	Jul-15	39	16	406	64			19	20	1,074	
2015	8	Aug-15	39	17	444	102			18	18	978	
2015	9	Sep-15	39	21	544	302			19	24	1,240	
2015	10	Oct-15	39	17	432	595			19	33	1,733	
2015	11	Nov-15	39	23	587	841			18	30	1,693	
2015	12	Dec-15	39	24	620	1,106		**6,150**	19	40	2,099	**19,474**
2016	1	Jan-16	41	23	555	1,172			19	35	1,819	
2016	2	Feb-16	41	22	542	1,199			19	40	2,082	
2016	3	Mar-16	41	23	562	985			18	33	1,826	
2016	4	Apr-16	41	19	461	754			18	33	1,824	
2016	5	May-16	41	15	366	304			18	27	1,494	
2016	6	Jun-16	41	17	418	90			18	23	1,298	
2016	7	Jul-16	40	19	466	41			17	23	1,341	
2016	8	Aug-16	40	23	579	87			19	17	885	
2016	9	Sep-16	40	21	532	301			19	24	1,242	
2016	10	Oct-16	40	19	472	615			19	32	1,684	
2016	11	Nov-16	40	25	622	757			19	30	1,553	
2016	12	Dec-16	40	22	555	1,263		**6,130**	18	33	1,858	**18,907**
2017	1	Jan-17	40	23	586	1,195			19	39	2,073	
2017	2	Feb-17	40	23	583	1,082			19	36	1,912	
2017	3	Mar-17	40	16	395	1,131			19	34	1,790	
2017	4	Apr-17	40	18	440	726			19	29	1,524	
2017	5	May-17	40	18	439	298			19	30	1,563	
2017	6	Jun-17	40	18	442	144			19	22	1,143	
2017	7	Jul-17	40	16	408	52			19	18	954	
2017	8	Aug-17	41	17	410	65			19	18	922	
2017	9	Sep-17	41	20	489	232			18	20	1,130	
2017	10	Oct-17	41	16	397	591			19	31	1,657	
2017	11	Nov-17	41	20	491	1,026			19	34	1,770	
2017	12	Dec-17	41	22	532	1,218		**5,613**	19	36	1,904	**18,342**
2018	1	Jan-18	41	21	518	1,303			19	37	1,942	
2018	2	Feb-18	41	19	470	1,154			19	36	1,918	
2018	3	Mar-18	41	19	453	1,032			19	28	1,497	
2018	4	Apr-18	41	19	459	762			19	34	1,784	
2018	5	May-18	41	22	539	369			18	22	1,242	
2018	6	Jun-18	41	11	263	132			19	27	1,437	
2018	7	Jul-18	39	17	447	64			19	21	1,089	
2018	8	Aug-18	39	20	513	157			18	18	1,020	
2018	9	Sep-18	39	15	386	464			19	27	1,404	
2018	10	Oct-18	40	21	517	623			19	30	1,576	

Northland Utilities (NWT) Limited (Northland)
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Wekweeti

Residential

Year	Month	monthly	MRCNT	MRENCNS (MWh)	MRUPC (kWh)	MHDD (Yellowknife)	UPC (kWh)	Annual UPC (kWh)
2018	11	Nov-18	40	22	544	940		
2018	12	Dec-18	41	20	494	1,135		**5,603**
2019	1	Jan-19	41	24	584	1,354		
2019	2	Feb-19	40	16	392	1,233		
2019	3	Mar-19	41	24	583	862		
2019	4	Apr-19	41	19	452	681		
2019	5	May-19	41	19	460	449		
2019	6	Jun-19	41	17	424	174		
2019	7	Jul-19	40	16	401	106		
2019	8	Aug-19	40	17	434	163		
2019	9	Sep-19	40	17	413	302		
2019	10	Oct-19	40	17	413	572		
2019	11	Nov-19	41	30	730	927		
2019	12	Dec-19	41	9	224	1,375		**5,509**
2020	1	Jan-20	42	29	682	1,362		
2020	2	Feb-20	42	17	399	1,216		
2020	3	Mar-20	42	21	491	1,163		
2020	4	Apr-20	42	22	515	789		
2020	5	May-20	41	19	460	466		
2020	6	Jun-20	42	19	449	159		
2020	7	Jul-20	42	20	488	58		
2020	8	Aug-20	42	21	495	104		
2020	9	Sep-20	42	22	516	332		
2020	10	Oct-20	42	22	514	615		
2020	11	Nov-20	42	20	477	1,003		
2020	12	Dec-20	42	25	590	1,219		**6,075**
2021	1	Jan-21	42	24	582	1,233		
2021	2	Feb-21	42	22	531	1,302		
2021	3	Mar-21	42	28	666	1,109		
2021	4	Apr-21	42	9	226	799		
2021	5	May-21	42	23	540	457		
2021	6	Jun-21	42	16	392	133		
2021	7	Jul-21	42	20	475	76		
2021	8	Aug-21	43	19	435	150		
2021	9	Sep-21	42	18	440	281		
2021	10	Oct-21	44	24	546	479		
2021	11	Nov-21	44	24	553	873		
2021	12	Dec-21	44	22	506	1,408		**5,892**
2022	1	Jan-22	44	29	656	1,432	656	
2022	2	Feb-22	44	17	388	1,304	388	
2022	3	Mar-22	44	24	555	1,105	555	
2022	4	Apr-22	44	22	510	775	510	
2022	5	May-22	44	33	756	380	756	
2022	6	Jun-22			376		376	
2022	7	Jul-22			419		419	
2022	8	Aug-22			452		452	
2022	9	Sep-22			429		429	
2022	10	Oct-22			442		442	
2022	11	Nov-22			588		588	
2022	12	Dec-22			417		417	**5,989**
2023	1	Jan-23			563		563	
2023	2	Feb-23			482		482	
2023	3	Mar-23			477		477	
2023	4	Apr-23			450		450	
2023	5	May-23			480		480	
2023	6	Jun-23			376		376	
2023	7	Jul-23			419		419	
2023	8	Aug-23			452		452	
2023	9	Sep-23			429		429	
2023	10	Oct-23			442		442	
2023	11	Nov-23			588		588	
2023	12	Dec-23			417		417	**5,575**

Commercial

MCCNT	MCENCNS (MWh)	MCUPC (kWh)	Annual UPC (kWh)
19	35	1,829	
19	43	2,288	**19,025**
19	34	1,778	
18	34	1,913	
19	32	1,707	
19	31	1,608	
19	30	1,590	
19	24	1,286	
19	21	1,107	
19	20	1,058	
19	21	1,125	
18	29	1,598	
19	23	1,196	
19	49	2,591	**18,557**
16	30	1,853	
19	40	2,097	
19	34	1,782	
19	27	1,445	
19	24	1,255	
19	18	962	
19	17	877	
18	16	909	
18	22	1,216	
18	32	1,779	
19	36	1,920	
19	37	1,958	**18,051**
19	35	1,839	
19	39	2,032	
17	30	1,780	
19	41	2,182	
18	28	1,569	
19	29	1,524	
19	24	1,271	
19	20	1,039	
19	27	1,401	
18	27	1,498	
19	31	1,655	
18	44	2,461	**20,251**
19	38	1,983	
19	44	2,313	
19	34	1,783	
19	34	1,792	
19	6	296	
		1,289	
		1,050	
		1,000	
		1,220	
		1,610	
		1,598	
		2,261	**18,196**
		1,931	
		1,914	
		1,665	
		1,638	
		1,465	
		1,289	
		1,050	
		1,000	
		1,220	
		1,610	
		1,598	
		2,261	**18,641**

Northland Utilities (NWT) Limited (Northland)
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Wekweeti - Regression

WEKWEETI
Summary Output, Residential
Data: 2005:1 - 2019:12

Regression Statistics	
Multiple R	0.601632566
R Square	0.36196174
Adjusted R Square	0.35837726
Standard Error	73.40099025
Observations	180

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	544051.2272	544051.2	100.9801	4.20719E-19
Residual	178	959011.5557	5387.705		
Total	179	1503062.783			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
INTERCEPT	418.781332	9.65379229	43.37998	1.42E-96	399.7307228	437.831941	399.730723	437.831941
MHDD	0.1213862	0.012079566	10.04889	4.21E-19	0.097548615	0.14522379	0.09754862	0.14522379

Summary Output, Commercial
Data: 2005:1 - 2019:12

Regression Statistics	
Multiple R	0.762093244
R Square	0.580786112
Adjusted R Square	0.578430978
Standard Error	255.8640982
Observations	180

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	16144301.77	16144302	246.6043	1.94608E-35
Residual	178	11653025.74	65466.44		
Total	179	27797327.51			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
INTERCEPT	1204.430244	33.65157405	35.7912	3.09E-83	1138.022871	1270.83762	1138.02287	1270.83762
MHDD	0.661239903	0.042107434	15.70364	1.95E-35	0.578145898	0.74433391	0.5781459	0.74433391

Northland Utilities (NWT) Limited (Northland)
2023 Amended General Rate Application (GRA)
Hay River - HDD

Hay River Heating Degree Day (HDD) Degree Days Below 18.0 ºC Month	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	20-year Normal HDD (2002-2021)
JAN	1,225.8	1,217.8	1,345.8	1,259.5	1,164.8	1,108.2	1,215.4	1,237.6	1,229.1	1,289.0	1,184.0	1,291.6	1,199.7	1,224.6	1,087.4	1,072.0	1,265.3	1,223.3	1,289.1	1,099.0	1,262.7	**1,211.4**
FEB	1,069.3	1,152.0	1,066.5	1,034.4	927.4	1,168.2	1,201.8	1,084.9	900.2	1,007.4	913.4	927.5	1,188.5	1,104.0	1,049.9	947.7	1,043.5	1,153.3	1,105.6	1,227.0	1,199.9	**1,063.6**
MAR	1,141.5	1,054.1	1,030.1	949.1	904.4	1,099.9	1,090.8	1,116.3	718.9	1,041.3	991.7	1,076.5	1,121.2	954.7	924.9	1,033.4	991.8	709.7	1,078.1	1,030.5	1,047.1	**1,002.9**
APR	791.0	575.7	651.2	542.4	497.2	559.6	689.4	623.2	491.0	720.1	676.1	785.1	690.5	571.3	682.6	667.3	723.0	566.6	734.2	698.4	706.9	**646.8**
MAY	524.8	357.4	532.3	407.1	312.1	368.0	358.0	489.9	401.5	360.5	276.5	332.8	380.4	304.6	312.2	283.9	326.6	432.8	459.8	402.8	393.1	**381.2**
JUN	146.7	201.4	211.4	208.8	98.3	161.2	154.9	192.7	120.0	168.2	155.5	134.7	157.8	126.0	105.1	151.5	157.2	196.2	206.6	146.2	0.0	**160.0**
JUL	93.3	68.9	69.8	86.0	85.2	37.8	35.2	101.3	45.3	36.6	13.3	82.6	34.6	67.2	47.0	55.7	74.2	100.1	75.6	64.2	0.0	**63.7**
AUG	156.0	118.4	177.6	143.2	90.1	187.3	102.8	87.7	109.4	85.7	59.5	77.7	104.4	97.5	79.4	60.3	118.7	152.7	115.8	118.0	0.0	**112.1**
SEP	274.5	285.4	331.1	308.0	203.1	365.5	315.4	176.8	293.5	205.7	178.2	179.7	273.8	264.3	249.5	204.8	424.7	265.0	273.3	233.0	0.0	**265.3**
OCT	612.8	459.3	614.7	473.7	524.3	489.4	477.7	559.7	463.7	470.8	574.9	458.2	521.3	507.9	566.3	507.0	565.8	516.2	585.7	457.7	0.0	**520.4**
NOV	778.9	884.4	852.4	767.1	1,042.4	849.8	777.7	824.5	810.3	952.1	1,010.5	886.6	909.6	767.7	721.8	975.5	879.9	848.6	927.2	822.1	0.0	**864.5**
DEC	923.4	1,024.2	1,244.4	866.3	925.2	1,188.0	1,280.6	1,163.4	1,214.7	978.4	1,328.4	1,339.9	1,143.9	1,024.8	1,191.4	1,084.2	1,046.4	1,226.5	1,076.9	1,336.5	0.0	**1,130.4**
TOTAL	**7,738.0**	**7,399.0**	**8,127.3**	**7,045.6**	**6,774.5**	**7,582.9**	**7,699.7**	**7,658.0**	**6,797.6**	**7,315.8**	**7,362.0**	**7,572.8**	**7,725.5**	**7,014.6**	**7,017.5**	**7,043.3**	**7,617.1**	**7,391.0**	**7,927.9**	**7,635.4**	**4,609.7**	**7,422.3**

Northland Utilities (NWT) Limited (Northland)
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Yellowknife - HDD

Yellowknife Heating Degree Day (HDD) Degree Days Below 18.0 °C Month	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	20-year "Normal" HDD (2002-2021)
JAN	1,342.1	1,365.4	1,470.0	1,376.2	1,239.0	1,220.9	1,364.8	1,352.9	1,307.3	1,394.2	1,251.6	1,427.8	1,342.7	1,340.3	1,172.4	1,194.6	1,303.1	1,354.0	1,362.4	1,232.5	1,431.7	**1,320.7**
FEB	1,164.8	1,288.2	1,139.2	1,140.3	993.7	1,205.4	1,297.2	1,160.8	960.1	1,139.9	1,013.4	1,035.4	1,233.9	1,229.7	1,198.6	1,082.3	1,154.0	1,233.3	1,216.1	1,302.1	1,303.8	**1,159.4**
MAR	1,228.5	1,163.7	1,151.2	1,027.3	895.9	1,180.2	1,183.6	1,187.9	866.0	1,109.0	1,059.1	1,128.0	1,191.5	1,038.9	985.3	1,131.0	1,032.0	862.2	1,163.0	1,109.0	1,104.6	**1,084.7**
APR	885.7	620.0	801.1	612.5	597.2	629.2	760.5	691.0	514.9	816.5	723.4	809.1	768.6	660.7	753.6	725.6	762.1	680.5	788.9	799.4	775.3	**720.0**
MAY	554.9	402.8	605.9	459.1	306.8	385.9	334.9	516.3	384.4	327.3	310.8	353.2	408.2	323.0	304.3	297.6	369.4	448.9	465.6	457.0	380.2	**400.8**
JUN	130.9	166.4	188.8	165.1	80.6	149.0	132.6	174.8	109.0	148.0	79.2	105.0	114.3	114.3	89.7	143.5	132.2	173.5	158.9	132.9	0.0	**134.4**
JUL	62.3	45.0	49.5	84.1	59.3	20.2	32.8	79.7	40.3	25.7	7.1	80.1	40.2	63.5	40.8	52.3	63.5	106.2	58.4	76.0	0.0	**54.4**
AUG	176.2	119.5	177.9	154.5	84.8	180.9	114.6	101.7	89.8	88.2	63.9	98.6	136.1	101.8	87.1	65.1	157.0	162.9	104.3	149.5	0.0	**120.7**
SEP	310.4	289.5	373.3	363.8	243.9	392.0	369.3	227.0	307.6	241.7	202.9	244.9	346.4	301.7	301.2	231.7	464.0	302.0	331.5	280.5	0.0	**306.3**
OCT	671.3	479.3	681.0	546.9	581.8	561.8	518.0	603.0	544.3	514.3	600.6	517.8	558.9	595.0	614.8	591.1	623.1	571.5	615.3	478.5	0.0	**573.4**
NOV	878.9	937.6	988.6	811.5	1,063.0	907.7	826.9	866.5	899.1	985.0	1,065.8	962.8	1,035.6	841.1	756.5	1,026.2	940.3	927.1	1,002.8	873.1	0.0	**929.8**
DEC	993.6	1,118.3	1,383.3	966.7	1,015.1	1,305.9	1,420.4	1,238.3	1,237.8	1,099.5	1,401.9	1,500.9	1,213.4	1,106.0	1,263.4	1,217.7	1,135.2	1,375.2	1,218.5	1,408.0	0.0	**1,231.0**
TOTAL	**8,399.6**	**7,995.7**	**9,009.8**	**7,708.0**	**7,161.1**	**8,139.1**	**8,355.6**	**8,199.9**	**7,260.6**	**7,889.3**	**7,779.7**	**8,263.6**	**8,389.8**	**7,716.0**	**7,567.7**	**7,758.7**	**8,135.9**	**8,197.3**	**8,485.7**	**8,298.5**	**4,995.6**	**8,035.6**

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Section 3 – Purchase Power

Overview

1. As discussed in Section 1, the 2023 forecast excludes the Purchase Power for Hay River, effective January 1, 2023. The Purchase Power included in this Application is outlined in Schedule 4.3 and is set out in the following table.

Table 3-1 – Purchase Power
($000s)

	2019	2020	2021	2022	2023
	Actual			Forecast	Test Year
Purchase Power	3,765	3,632	3,704	3,565	307

2. The Hay River Disposition results in 2023 Purchase Power expenses decreasing by 91 percent or $3,258,000 compared to forecast costs for 2022.

3. In the Test Year, 37 percent of Northland's total required power supply is forecast to be purchased from NTPC, down from 84 percent in 2022, due to the Hay River Disposition. The purchased power in 2023 is required for the remaining customers in the Hydro zone.

Deferral Account

4. Consistent with previous approvals, Northland is requesting continued approval of purchase power deferral.

5. Consistent with the previously approved methodology, the purchase price is based on NTPC's approved rates that were in effect on May 1, 2022. Subsequent increases or decreases to these rates approved by the Board for 2023, and subsequent years, will be flowed through to Northland's customers using the existing Rider F, as approved by the Board.

6. Further, Northland is proposing to use the purchase power deferral to recover losses and station service usage during any interim period between

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January 1, 2023, and the final transition of the Franchise Assets to the Town, while Northland is still purchasing energy at Pine Point. For customers in Hay River, as described in Section 15, the existing Rider F will remain for any period of time where Northland owns and operates the Franchise Assets beyond January 1, 2023, and the existing NTPC Wholesale Rate remains unchanged. As described in Section 1B, any deferral balance will be trued-up at the time of the transition.

7. Post transition, Northland has assumed it will no longer purchase power at Pine Point and will, instead, purchase power further downstream off the Hay River Distribution system.

Forecast Process

8. The energy component of the purchase power cost is determined by applying NTPC's rates to the total forecast energy (kWh) purchases as shown on Schedule 4.3. Line losses have been forecast using the methodology described in Section 4. Total forecast purchases are determined by applying line loss percentages to Northland's sales load forecast.

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Section 4 – Diesel Fuel Costs

Overview

1. As discussed in Section 1, the 2023 forecast excludes the purchase power for Hay River, effective January 1, 2023. The diesel fuel costs included in this Application are outlined in Schedule 4.1 and are set out in Table 4-1, below.

Table 4-1 – Diesel Fuel Costs (Schedule 4.1)
($000s)

	2019	2020	2021	2022	2023
	Actual			Forecast	Test Year
Diesel Fuel Costs	1,527	1,325	1,463	2,618	1,932

2. The actual diesel fuel cost increase of $1,091,000 from 2019 to 2022 is mainly due to the increase in the price of diesel fuel. The forecast for the 2023 Test Year decreased by $686,000 mainly due to the Hay River Disposition.

3. Please refer to Schedule 4.1 for the details associated with the calculation of diesel fuel costs for 2019 to 2023.

Background

4. Diesel fuel is purchased for each of the diesel plants operated by Northland. Northland conducts a fuel tendering process through which a vendor is selected to be the exclusive provider of fuel to Northland.

5. Fuel costs are recorded as the diesel fuel is consumed by the diesel plant.

Forecasting Fuel Costs

6. Diesel fuel costs are a function of forecast sales, station service, line losses, plant efficiencies, and delivered fuel prices.

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Station Service

7. In accordance with Board Direction 18 in Decision 25-2008, forecast station service has been calculated using a weighted average of three years of actual data with a weighting of “3” given to the lowest station service year, a weighting of “2” to the middle station service year, and a weighting of “1” to the highest station service year.

Line Losses

8. In accordance with past practice, forecast line losses were determined for the level of line losses in each community.

Plant Efficiencies

9. In accordance with Board Directions 14 and 15 in Decision 25-2008, forecast plant efficiencies were calculated using a weighted average of three years of actual data with a weighting of “3” given to the highest efficiency year, a weighting of “2” to the middle efficiency year and a weighting of “1” given to the lowest efficiency year, adjusted for the forecast fuel efficiencies of any new engines forecast to be in service.

Fuel Price Forecasts

10. Price forecasts for each community are based on the current prices in place for diesel fuel as of June 2022. The respective fuel prices for each location are shown in Schedule 4.1.

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Deferral Accounts

(a) Diesel Fuel Price Variance

11. Consistent with the previously approved deferral account, Northland proposes to continue to refund, or collect from, customers the variance between actual and forecast fuel prices

(b) Hay River Diesel Generation Variance

12. Northland proposes that the Hay River Diesel Generation Deferral will remain in place as it operates today until the closing of the purchase and sale transaction related to the Franchise Assets, and will be trued-up at the same time as the Hay River Transition Deferral proposed in Section 1B. Upon transfer of the Franchise Assets, the deferral account balance will transfer to the Town. The Deferral account will operate as before, as described in the following paragraphs.

13. Northland proposes the variance between actual and forecast fuel and O&M costs associated with operating the Hay River generation facilities, for a level of generation that is greater or less than the 4.2 percent of total supply included in this Application, continue to be recovered from, or refunded to, customers, as applicable, subject to Board approval. The use of 4.2 percent of total supply is based on previously approved generation requirements.

14. The deferral balance will track for recovery (or return) actual incremental O&M costs or savings associated with the level of generation being greater than or less than the 4.2 percent of total supply included in this Application.

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Section 5 – Operations and Maintenance (O&M) Expenses

Overview

1. As discussed in Section 1, the 2023 forecast excludes operating and maintenance costs and other taxes attributable to the Hay River Franchise, effective January 1, 2023.

Operations and Maintenance (O&M) Expenses

2. Total O&M expenses included in this Application, as outlined and explained in detail in Schedules 5.1, 5.2 and 5.3, are as follows:

Table 5-1 - Operations and Maintenance (O&M) Expenses ($000s)

Operations and Maintenance Expense	2019	2020	2021	2022	2023
	Actual			Forecast	Test Year
Production	1,028	1,014	1,015	1,055	727
Transmission	57	67	67	84	75
Distribution	1,047	939	1,326	1,355	421
General	40	38	41	40	31
Public Information	93	63	73	76	68
Customer Accounting	447	442	319	424	174
Administration and General	1,329	1,383	1,488	1,402	1,024
Other Taxes	363	374	369	367	5
Less Donations	(9)	(7)	(9)	(14)	(10)
Total	**4,395**	**4,313**	**4,689**	**4,789**	**2,516**

Forecast Process

3. Development of Northland's O&M forecast for the 2023 Test Year involved a detailed review of the business requirements after the Hay River Disposition to continue the provision of safe and reliable electricity service for the remaining communities and the transmission facilities from Pine Point to Hay River. The O&M

forecast for the Test Year was developed using the best information available at the time. Separate forecasts were developed for labour and non-labour costs.

4. Northland's year over year variances between actuals and forecast costs during the 2019 to 2022 period were mainly attributable to the deferral of line and substation maintenance expenses in 2020 when contractors were unavailable due to COVID-19 restrictions. To make up for O&M activities that were deferred in 2020, the maintenance schedule was expanded in 2021 and 2022 when restrictions lifted, and contractors were available again. Aside from inflationary increases, the three-year average O&M expenses from 2020-2022 remained flat compared to 2019 O&M expenses.

5. The forecast for the 2023 Test Year was developed by examining labour and non-labour costs in each activity of the business to identify costs required to operate in the remaining communities after the Hay River Disposition. Please refer to Schedule 5.2 for an explanation of the methodologies used for each activity for 2023.

Labour Costs

6. Labour costs are calculated based on the rate of pay for each required job class. These labour costs are then distributed to O&M accounts or capital accounts depending on the nature of work being performed by the staff in that job class.

7. When the Hay River Franchise was not renewed, Northland made the decision not to replace vacant permanent PLT positions, and instead utilized Alberta-based PLT Services until the terms of the Hay River Disposition were resolved. In 2019 through 2022, Powerline Technician (PLT) services were contracted from ATCO Electric in the amounts of $0.5 million, $0.4 million, $0.9 million, and $1.0 million, respectively. The related party PLT costs have been removed from the forecast for the 2023 Test Year.

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8. To continue to provide safe and reliable service to remaining customers in 2023, Northland will require 5.96 FTEs, five (5) of which are full time to Northland and 0.96 of which are shared employees with Northland Utilities (Yellowknife) Ltd. Consistent with Northland's past practice, this will maximize efficiencies and take advantage of economies of scale. This complement ensures that Northland has the right skillsets available and proper coverage for standby and vacations; however, this is the minimum number of FTEs possible to operate the system safely and reliably, recognizing that vacancies or leave time must be filled with contractors or external resources going forward. In addition, Northland will receive services from ATCO Electric equating to 3.01 FTEs, further discussed below. Please refer to Attachment 1 for the 2023 Organization Chart and Schedule 5.2.

Defined Benefit and Defined Contribution Pension Plans Cash Contributions and Defined Benefit Deferral Account

9. As a result of the defined benefit pension plan actuarial valuations of assets and liabilities, pension funding requirements have changed as shown below.

Year	Defined Benefit (Annual Lump Sum, $000s)
2019	99
2020	42
2021	52
2022	53

10. Consistent with Northland's most recent GRAs, forecast pension expense is based on the cash basis for the Test Year.

11. For purposes of this Application, the 2023 Test Year assumes the same defined benefit contribution rates as 2022. For 2023, Northland is seeking approval to continue the existing deferral account to flow through increases or decreases to required cash contributions to the defined benefit pension plan. This request is

based on the need for annual actuarial valuations to determine defined benefit pension funding for the year beginning January 1, 2023.

12. Northland also has a defined contribution pension plan that applies to employees that were hired after January 1, 1997. The company's contribution to the defined contribution plan is six percent.

Non-Labour Costs

13. Non-labour costs are forecast in two parts: (i) ongoing operational and administrative activities, and (ii) new programs or projects.

14. In the Test Year, ongoing operational and administrative costs were forecast based on activities required to provide safe and reliable service. Cost drivers were examined and used; for example, costs that closely follow the FTE count (training and staff expenses, etc.) were based on the remaining FTE count. Other drivers used included, remoteness of communities, number of remaining customers and energy consumption. There were also Administrative and General costs that are fixed regardless of the size of the company (e.g., Audit Fees, Financial Services, etc.).

15. In the 2023 Test Year, Northland did not include any additional costs for new O&M programs or one-time projects.

16. For more detail on the buildup of the 2023 O&M forecast refer to Schedule 5.2.

Related Party Costs

17. Northland continues to outsource certain administrative functions to related party companies, such as ATCO Electric, to take advantage of the economies of scale associated with obtaining services from a larger utility. The cost of these services is detailed in Schedule 12.0 and is based on a fully allocated cost methodology that does not contain any element of profit or return.

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18. Northland purchases labour support from ATCO Electric for various services including financial reporting, after-hours assistance, ongoing regulatory support, human resources, governance and communications. The 2023 head office support costs are based on historical requirements and adjusted for known changes. The Hay River Disposition had very little impact on the requirement for these services in 2023 compared to prior years.

19. In addition to the typical support costs purchased from ATCO Electric, Northland has been utilizing Alberta-based PLT services to cover vacant PLT positions due to the uncertainty of the outcome surrounding the Hay River Disposition. These services will no longer be required after the closing of the purchase and sale transaction related to the Franchise Assets and have been excluded from the 2023 forecast.

20. Refer to Schedule 12.0 for Related Party Costs in O&M.

Common Costs – Post Hay River Disposition

21. Northland has allocated common costs in accordance with Decision 1-2016. For the 2023 Test Period all operating and administrative costs, including common costs, were reduced to reflect reductions in the cost drivers as a result of the disposition of Hay River. Northland iterates that a portion of administrative costs are fixed in nature, regardless of the size of the customer base Northland serves. Northland is a taxable, legal entity and will continue to incur costs associated with financial reporting, management reporting, asset management, taxation and regulatory requirements following the disposition of Hay River.

Taxes Other than Income

22. Total taxes other than income included in this Application are included in the table below.

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Table 5-2 – Total Taxes other than Income
($000s)

Other Taxes		2019	2020	2021		2022	2023
		Actual				Forecast	Test Year
Franchise Taxes		324	334	324		321	-
Property Taxes		39	40	45		46	5

23. Following the Hay River Disposition, no communities served by Northland will impose a franchise fee in 2023 as they are not tax-based communities.

24. The franchise fee paid to the Town in actuals/forecast is based on the terms of the Franchise Agreement from June 2, 2006, which granted Northland exclusive rights for the distribution of electrical energy to the Town and its residents until November 30, 2016. In line with the terms in the Franchise Agreement, Northland will continue to pay and recover the franchise fee until the purchase and sale transaction related to the Franchise Assets has closed. Franchise fees are recovered from customers through the Franchise Fee Rider, which is a flow-through of the fee paid to the Town. It is currently calculated based on four percent of revenue generated from the sale of electricity in the Town of Hay River. Northland will no longer require the Franchise Fee Rider in 2023 after the closing of the purchase and sale transaction related to the Franchise Assets. As discussed in Section 1B, Northland will continue to charge existing rates to Hay River customers for the period it operates the Franchise Assets in 2023, with any balances trued-up in the transition deferral.

25. Property taxes are paid to the communities annually for Northland's office building, generation facilities, substation properties and power lines. The 2023 property taxes have been reduced to exclude the Franchise Assets.

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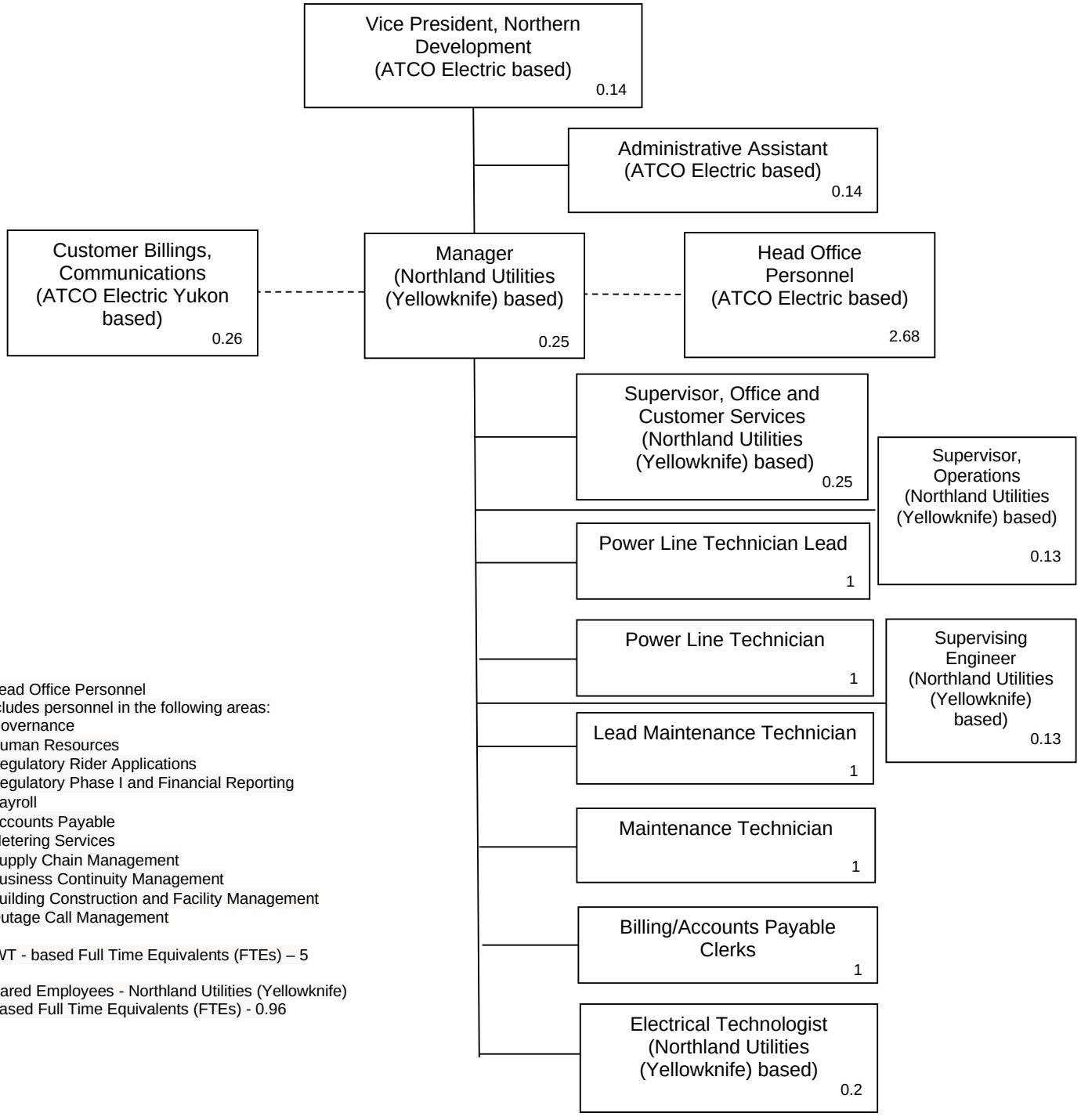
Organizational Chart
Northland Utilities (NWT) Limited
2023



*Head Office Personnel
Includes personnel in the following areas:
- Governance
- Human Resources
- Regulatory Rider Applications
- Regulatory Phase I and Financial Reporting
- Payroll
- Accounts Payable
- Metering Services
- Supply Chain Management
- Business Continuity Management
- Building Construction and Facility Management
- Outage Call Management

NWT - based Full Time Equivalents (FTEs) – 5

Shared Employees - Northland Utilities (Yellowknife) - based Full Time Equivalents (FTEs) - 0.96

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Section 6 – Depreciation

Overview

1. As discussed in Section 1, the 2023 forecast excludes the depreciation for Franchise Assets, effective January 1, 2023. The Depreciation Expense included in this Application, and outlined in Schedules 6.1 through 6.3 is as follows:

Table 6-1 – Depreciation Expense
(Schedules 6.0, 6.1 and 6.4)
($000s)

	2019	2020	2021	2022	2023
	Actual			Forecast	Test Year
Depreciation Expense	1,494	1,471	1,481	1,493	803

2. Northland is not requesting any changes to previously approved depreciation rates or parameters in this Application.

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Section 7 – Return on Rate Base

Overview

1. The Return on Rate Base included in this Application is outlined in Schedule 7.0 and is as follows:

Table 7-1 – Return on Rate Base
(Schedule 7.0)
($000s)

	2019	2020	2021	2022	2023
	Actual			Forecast	Test Year
Return on Rate Base	1,009	1,171	982	820	514

2. The increase in the Return on Rate Base between 2019 and 2020 is mainly due to lower operating costs due to travel restrictions and higher tax deductions. The 2023 Return on Rate Base is reflective of removal of rate base related to the Hay River Disposition.

3. The components of the return on rate base are as follows and are discussed below:

    1. Cost of Capital
        - o Capital Structure and Cost of Capital
        - o Risk Premium
        - o Forecast Long Term Debt Rates
        - o Customer Deposits
        - o No Cost Capital
    2. Rate Base
        - o Capital Additions
        - o Contributions
        - o Deferred Charges & Credits
            - ▪ Attachment 1 – Schedule of Plant Maintenance 2019-2023
    3. Working Capital
        - o Overview

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Cost of Capital

Background

4. Northland's most recent Cost of Capital was determined by way of a negotiated settlement in its 2014-2015 GRA. In Decision 9-2014, the Board determined that the Return on Equity (ROE) would be the generic ROE determined by the AUC in the 2013 GCOC Proceeding,[1] plus a risk premium of 0.35 percent. Similarly, the common equity ratio would be equal to that of ATCO Electric Distribution, plus five percent to align Northland with the common equity ratios of comparator utilities.

5. The ROE set by the AUC in the 2013 GCOC Decision[2] was 8.3 percent. ATCO Electric Distribution was awarded an equity ratio of 38 percent. Therefore, Northland's current ROE is 8.65 percent, and its current common equity ratio is 43 percent:

Table 7-2 – Current Approved

	ROE	Common Equity (%)
2013 GCOC	8.3%	38
Plus	35 bps	5
Equals	**8.65%**	**43**

6. Prior to Decision 9-2014, in Decision 25-2008, the Board approved a 9.15 percent ROE and 44 percent equity ratio. In that Decision, the Board stated: "NUL's business risks are somewhat higher than those of an average electric utility due primarily to its small size and economic characteristics of the service area."[3]

Approvals Sought

7. Consistent with past Board findings, Northland respectfully requests that the Board approve an update to Northland's ROE and common equity to reflect the AUC's

[1] Proceeding ID 2191.
[2] Decision 2191-D01-2015.
[3] Decision 25-2008, NWT Phase 1 GRA, page 14.

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2023 GCOC Decision, which approved an ROE of 8.5 percent and common equity ratio of 37 percent for ATCO Electric Distribution,[4] as a starting point in determining Northland's ROE and Equity ratio.

8. Further, Northland respectfully requests that the Board approve an increase to its equity risk premium from 0.35 percent to 1.25 percent to reflect its increased business risk following the Hay River Disposition. Northland is not seeking a change to the five percent adder to its common equity ratio.

9. If approved as filed for 2023, Northland's cost of capital would be as follows:

Table 7-3 – Proposed Cost of Capital

	ROE	Common Equity (%)
AUC Approved 2023 GCOC	8.5%	37
Plus	125 bps	5
Equals	**9.75%**	**42**

10. The proposed changes will ensure that Northland has an opportunity to earn a fair return,[5] with the approvals sought reflecting the change in business risk affecting Northland following the Hay River Disposition. Section 50 of the *PUA* requires the Board to fix a fair return on equity on the rate base of public utilities. This includes setting the portion of rate base financed by common equity.

AUC-Approved 2023 GCOC

11. In Decision 9-2014, the Board adopted the AUC's latest approved GCOC for both the ROE and Common Equity as a starting point. Northland submits the latest AUC approval for cost of capital continues to be a reasonable starting point for determining Northland's ROE and Common Equity. In Decision 27084-D01-2022,

[4] Decision 27084-D01-2022.
[5] By a fair return is meant that the company will be allowed as large a return on the capital invested in its enterprise (which will be net to the company) as it would receive if it were investing the same amount in other securities possessing an attractiveness, stability and certainty equal to that of the company's enterprise… The duty of the Board was to fix fair and reasonable rates; rates which, under the circumstances, would be fair to the consumer on the one hand, and which, on the other hand, would secure to the company a fair return for the capital invested. *Northwestern Utilities Ltd. v. Edmonton (City)*, [1929] SCR 186 at 192-93, [1929] 2 DLR 4 *TransCanada Pipelines Ltd. (Re)*, 2013 LNCNEB 2, at paragraph 565.

the AUC approved a ROE of 8.5 percent and Common Equity of 37 percent for the Distribution Utilities in Alberta except for Apex Utilities:

> In this decision, the Alberta Utilities Commission approves the return on equity (ROE) of 8.5 per cent and deemed equity ratio of 37 per cent, except for an approved deemed equity ratio for Apex Utilities Inc. of 39 per cent (together, the ROE and deemed equity ratios are also referred to as "parameters") for 2023 on a final basis.[6]

Risk Premium – ROE

12. Since Decision 9-2014, Northland's risk profile has increased due to the Hay River Disposition. As will be detailed throughout this Section, Northland is requesting a ROE risk premium of 125 basis points, up from the currently approved 35 basis points.

13. As shown in the table below, customer counts and billing determinants have decreased significantly, geographic spread has been accentuated, and sales and service have shifted on balance to communities where Northland is the main generator (using thermal assets), as well the distributor. This has resulted in increased market demand and operational risk as discussed further below. Please refer to Table 7-4 below:

Table 7-4 – Asset Disposition

	2022 Forecast	2023 Test Year	
	Before Hay River Asset Disposition	After Hay River Asset Disposition	% Change
Customer count (Residential + Commercial)	2,631	736	(72%)
Rate Base ($000s)	13,501	7,648	(43%)
Purchases (MWh)	30,825	2,536	(92%)
Sales (MWh)	32,988	6,315	(81%)
Proportion of Purchases to Sales	93.4%	40.1%	(57%)
Revenue Requirement ($000s)	$13,538	$5,463	(60%)

14. The substantial changes resulting from the Hay River Disposition have altered Northland's operations to a level not previously seen in past rate Applications,

[6] Decision 27084-D01-2022, paragraph 1.

thereby requiring an increase to Northland's risk premium. Consistent with Decision 25-2008, the additional business risk must be contemplated in the risk premium awarded (over and above the AUC starting point).

15. In addition, in Decision 25-2008, the Board recognized that interest coverage and funds from operations (FFO) interest coverage ratios are one set of factors among many others that rating agencies have regard to in assessing investment risk.[7] Please refer to Table 7-5 below for Northland's interest coverage and FFO interest coverage ratios.

Table 7-5 – Interest Coverage and FFO Interest Coverage Ratios

	2010 per Decision 25-2008	2023 Test Year (as proposed)
Interest Coverage	2.78	1.06
FFO Interest Coverage	4.90	5.93

Market Demand Risk

16. Market demand risks relate to the volatility of sales and their impact on the fair return. With the Hay River Disposition, this risk has increased significantly compared to past proceedings. Northland is more susceptible to many variables including the weather (particularly given the range of temperatures in northern Canada), seasonal volatility of business activity, concentration of sales among fewer customers, the economic health of the community at large, as well as adoption of new technologies and decarbonization, both of which are reflected in the net metering program and government policy. For example, one of the guiding principles of the GNWT's 2030 Energy Strategy is the transition to a lower carbon economy by reducing GHG emissions, increasing the use of renewable and alternative energy and improving energy efficiency within its own operations.

17. Since the last cost of capital review, transformational change has started to occur in the electric utility industry with emphasis on decarbonization, increased focus

[7] Decision 25-2008, NWT Phase 1 GRA, page 15.

on Environmental, Social and Governance (ESG), the need for grid modernization, and general changes to the way in which customers receive utility service (e.g., self-supply). These changes increase risk and uncertainty for utilities to a level never experienced before, and particularly affect Northland because of its small customer base over which costs can be shared.

18. Compounding Northland's risk is the fact that it serves a relatively small market with considerably less economic strength and diversity than the service areas of other utilities. Northland does not have any industrial customers and its residential and commercial sales are primarily affected by the general economic activity within the communities served. The loss of revenue from a few customers has a greater effect on Northland than it does on a larger utility with a larger, more diverse customer base.

19. Finally, the Hay River Disposition has the effect of increasing the size of NTPC and restricting Northland's opportunities to grow its business.

Operating Cost Risk

20. Operating cost risks essentially comprise the potential for the actual ROE to fall short of the approved ROE due to under-estimation of capital expenditures, financing costs, and O&M expenses. The uncertainty of O&M expenses has increased for Northland since the last cost of capital review. Northland is not immune from the recent supply chain disruptions and high rates of inflation affecting the world today. In fact, the risks are higher for Northland due to the remote locations it serves, particularly after the Hay River Disposition, which may result in higher than anticipated repair costs for unplanned maintenance for either generation or distribution facilities. For example, in an unplanned maintenance situation, flights must be chartered for staff and materials to allow timely access into certain communities. This increases the risk from both a cost perspective and service level commitment, all of which is further complicated by the complexities resulting from transformational changes and their effect on the system.

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21. Operating risk is further elevated by the unpredictable and extreme weather conditions that can occur in northern Canada. Repair costs can deviate substantially from those forecast in operating budgets which are based on normal weather conditions. The length of the winter period increases the probability that these severe weather conditions can be experienced. Supply and physical risks faced by Northland must also be considered, such as loss of supply. Due to the harsh physical and climate characteristics, as well as the geographic spread, of Northland's remaining service territory (post Hay River Disposition), the risk is greater for Northland than for other utilities that a loss of supply may result in reduced revenues and earnings.

22. As mentioned above, following the Hay River Disposition, Northland's profile has proportionally shifted to being more of a generator (using thermal assets), as well as a distributor. It is an established principle that generation facilities are riskier than transmission or distribution facilities.[8] Following the Hay River Disposition, generation-related facilities now comprise 26 percent of Northland's PPE (compared with 15 percent pre-disposition), clearly indicating that Northland's operational risks have increased.

23. Given the foregoing, Northland submits that its request for a 125-basis point equity risk premium is reasonable and appropriate. Since the last review by the Board, the risk profile from both a market demand and operational standpoint has increased significantly, particularly following the Hay River Disposition. Northland submits that the requested ROE risk premium will ensure these additional risks are factored into providing the utility with an opportunity to earn a fair return.

[8] British Columbia Utilities Commission Generic Cost of Capital Proceeding Stage 2, Exhibit B1-72, FBC Evidence, Appendix B, McShane Evidence pages 14-15.
GCOC Stage 2 - FBC Evidence (bcuc.com), accessed June 30, 2022.

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Comparator Utilities

24. Another factor that must be contemplated as part of ensuring Northland has an opportunity to earn a fair return is conducting a comparability assessment to other jurisdictions. Northland has compiled Table 7-6 below containing information about similar utilities including their approved ROE and common equity ratios.

Table 7-6 – Information on Comparator Utilities

Utility	Equity Ratio	ROE	Customer Count	Total Sales	Rate Base	Decision Reference
Northland (2023F)	**42%**	**9.75% (Includes 1.25% equity risk premium)**	**736**	**631 MWh**	**$10.63M**	**TBD**
Northland Utilities (Yellowknife) Limited	43%	9.30%	7,952 (2010 actual)	156 GWh (2010 actual)	$36.7M (2010 actual)	12-2011
ATCO Electric Yukon	40%	9.00% (including 0.25% equity risk premium)	17,600 (2015 actual)	315.89 GWh (2015 actual)	$93.0M (2015 actual)	2017-01
FortisBC Inc. (FBC)	40%	9.15% (including 0.40% equity risk premium)	147,199	3,306 GWh	$1.58B	G-75-13
Maritime Electric	45%	9.35%	84,000	1,326 GWh	$471M (2023F)	UE20944
Nova Scotia Power Inc.	37.5%	9.00%	525,000	10,196 GWh	$4.58B 2023F	NSUARB 42
Alaska Electric Light & Power Co. (AEL&P)	58.18%	11.95%	17,500	404 MWh	$109M (2013)	U-16-086

25. Due to Northland's unique characteristics that are described above, there are no direct comparators that face the same market and operational risks – particularly with respect to its size and operational challenges. However, both AEL&P and FBC are reasonable comparators for the following reasons.

26. AEL&P is a good comparator as it is the sole utility providing electrical energy service in Juneau, Alaska, which is a geographically isolated community with no electric interconnections. Similar to Northland's service territory, the local economy

in Juneau is driven by a few primary industries: government, tourism, commercial fishing, and mining. Like Northland, AEL&P has operating cost risk due to its lack of interconnectivity to any other electric grids and adverse impacts could result from an extended outage at one of its hydroelectric generating stations or the availability or cost of replacement power (i.e., diesel). On the other hand, with 17,500 customers, AEL&P has far more customers than Northland (with roughly 740 customers remaining after the Hay River Disposition).

27. Further, despite being on the lower range of ROEs, FBC is also a decent comparator utility because FBC is a fully integrated electric utility consisting of generation, transmission, and distribution. Similar to Northland, FBC has more concentrated assets and a less diverse customer base. However, as shown in the table above, FBC is orders of magnitude larger in size and does not face the same geographical challenges as Northland. Considering these differences, Northland submits that, based on its size and the geographical challenges it faces, a 125-bps ROE premium is appropriate.

28. As shown in Table 7-6, risk premiums are common and are based on the size and specific risks each utility faces. Given the range of approved ROEs shown in the table and the risks it faces, Northland submits the proposed overall return of 9.75 percent is reasonable.

Customer Deposits

29. The customer deposits, or security deposits, included in this Application relate to deposits paid by customers to Northland if they have been unable to establish a satisfactory credit rating, been disconnected or restricted by a current-limiting device or have not paid all past due charges. Customer deposits related to Hay River customers will be transferred as part of the Hay River Disposition. The balances of customer deposits included in Schedule 8.1 are as follows:

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Table 7-7 – Customer Deposits
($000)

	2019 Actual	2020 Actual	2021 Actual	2022 Forecast	2023 Test Year
Customer Deposits	190	190	196	196	35

Capital Additions

Table 7-8 – Rate Base
($000)

	2019 Actual	2020 Actual	2021 Actual	2022 Forecast	2023 Test Year
Capital Expenditures	695	771	935	1,463	2,624
Capital Additions to Rate Base	674	695	861	1,089	1,470

30. These additions are primarily driven by a requirement to upgrade, enhance and replace components on the distribution and generation systems as well as general property and equipment that have reached the end of their life cycle.

Contributions

31. Contributions in aid of construction are received from customers in accordance with the company's investment policy. The contributions outlined in Schedule 11.5 are:

Table 7-9 – Contributions
($000)

	2019 Actual	2020 Actual	2021 Actual	2022 Forecast	2023 Test Year
Contributions in Aid of Construction (per year)	187	294	413	209	4

32. Northland's forecast process involves a review of projects included in the capital additions outlined in Section 11 to identify those which will require a customer contribution.

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Deferred Charges and Credits

33. The mid-year deferred charges and credit amounts included in rate base are outlined in Schedule 11.7 and are as follows in the table below.

Table 7-10 – Deferred Charges and Credits
($000)

	2019 Actual	2020 Actual	2021 Actual	2022 Forecast	2023 Test Year
Mid-Year Balance	741	940	1,157	1,151	196

34. The deferred charges and credit amount in 2023 are reflective of a transfer of the balances related to Hay River customers as part of the Hay River Disposition and includes the following:

(a) Rate Case Reserve

35. Northland has continued using a reserve account to flow through rate case costs to customers for GRAs filings. The annual rate case write off has remained unchanged, $226,000 annually, from that approved in the 2014-2015 GRA through to 2022. In 2022 a placeholder of $550,000 costs has been forecast for the 2023 GRA. In 2023, Northland will transfer the balances of rate case reserve costs related to Hay River customers as part of the Hay River Disposition and the remaining $327,000 will be flowed through back to customers to bring the overall rate case reserve balance to $nil at the end of 2023.

(b) Reserve for Injuries and Damages

36. This reserve is used for uninsured and uninsurable losses and the deductible portion of insurance claims. Maintaining the reserve mitigates rate fluctuations by smoothing out the charges to O&M with respect to these types of losses. The establishment of the reserve provides financial advantages overpaying significantly higher insurance premiums to reduce deductibles or to insure items which carry prohibitively high premiums.

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37. The 2022 forecast for this reserve includes a placeholder of $50,000 costs for the damages caused by the unprecedented flood in Hay River in the Spring of 2022. The town issued an evacuation notice May 12, 2022, which was lifted May 19, 2022. Heavy flooding caused damage to Northland infrastructure included loss of approximately twelve distribution line poles throughout the Hay River area that required replacement, flooding of underground transformers that required cleaning and testing to put back into service, Additional manpower was brought in from Northland Yellowknife and NTPC to assist in repairs and patrols. Furthermore, numerous commercial and residential customers experienced flooding of homes and businesses, this required working closely with the GNWT electrical inspector to determine which ones could be left on and which would require isolation and repairs before reconnection. As discussions with insurance providers are ongoing Northland has put a placeholder to be trued up once finalized.

38. Consistent with the 2014-2015 Application, no charges are forecast for 2023. Northland will transfer the balances related to Hay River customers as part of the Hay River Disposition and the remaining $98,000 owing from customers at the end of 2022 over the test year to bring the overall reserve for injuries and damages balance to $nil at the end of 2023.

(c) Plant Maintenance Reserve

39. Northland continues to use a reserve account to flow through to customers the costs associated with cyclical top-end plant overhauls and rebuilds outside of Hay River. Please refer to Attachment 1 for a listing of actual, as well as, forecast overhauls for the period 2019-2023. The plant maintenance reserve write off has remained unchanged, $58,000 annually, from that approved in the 2014-2015 GRA through to 2022. Inclusive of the remaining $228,000 owing from customers in the test year, the overall plant maintenance reserve balance will be $nil by the end of 2023.

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40. Consistent with IFRS, major overhauls are capitalized and amortized over the period between the major overhauls.

Working Capital

41. Working capital is a component of the company's total rate base as generally the payment of expense occurs in advance of the receipt of revenues.

42. The components of working capital are:

- Purchase Power;
- Operating Expenses;
- Income Tax;
- Goods and Services Tax;
- Depreciation Expense;
- Interest Expense;
- Common Equity (retained earnings component);
- Common Equity (dividend component); and
- Materials and Supplies Inventory (based on the estimated inventory balance).

43. The nature of the revenues and expenses in the remaining communities and the payment terms from the previous lead/lag study have not changed materially since the preparation of the 2014-2015 GRA Application. However, in the test year each category in working capital was adjusted to remove Hay River related transactions. The removal of Hay River from working capital in 2023 was partially offset by the one-time tax credit for the implementation of the new billing system.

44. The working capital included in rate base in this Application is outlined on Schedule 11.9 with the details on the components incorporating working capital disclosed on Schedule 11.9 and is as follows:

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Table 7-11 – Working Capital
($000)

	2019 Actual	2020 Actual	2021 Actual	2022 Forecast	2023 Test Year
Working Capital	1,335	1,269	1,359	1,582	1,428

Northland Utilities (NWT) Limited (Northland)
2023 Amended General Rate Application (GRA)
Schedule of Plant Maintenance for 2019-2023
($000)

Line No.		Unit Info	Size (kW)	Type of Maintenance	Location	Amount
1	**2019 Actual**					
2						
3	CUL#324	Cat 3508	500	Top-End Overhaul	Fort Providence	23
4	CUL#506	Volvo TAD733GE	150	Top-End Overhaul	Dory Point	4
5						27
6	**2020 Actual**					
7						
8	CUL#324	Cat 3508	500	Top-End Overhaul	Fort Providence	69
9	CUL#570	Cummins QSK23	725	Top-End Overhaul	Fort Providence	131
10	CUL#587	Volvo TAD734GE	185	Top-End Overhaul	Wekweeti	5
11	CUL#594	Volvo TAD733GE	150	Top-End Overhaul	Wekweeti	7
12						213
13	**2021 Actual**					
14						
15	CUL#324	Cat 3508	500	Top-End Overhaul	Fort Providence	(13)
16	CUL#506	Volvo TAD733GE	150	Top-End Overhaul	Dory Point	4
17						(10)
18	**2022 Forecast**					
19						
20	CUL#506	Volvo TAD733GE	150	Spare Replacement	Dory Point	35
21	CUL#604	Volvo TAD733GE	150	Top-End Overhaul	Wekweeti	26
22						61
23	**2023 Test Period**					
24						
25	CUL#570	Cummins QSK23	725	Top-End Overhaul	Fort Providence	90
26	CUL#603	Volvo TAD733GE	150	Top-End Overhaul	Samba' Ke	36
27	CUL#594	Volvo TAD733GE	150	Top-End Overhaul	Wekweeti	31
28	CUL#587	Volvo TAD734GE	185	Top-End Overhaul	Wekweeti	38
29						195

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Section 8 – Income Taxes

Overview

1. The Income Tax expense included in this Application is outlined in Schedule 8.0 and is as follows:

Table 8-1 – Income Tax
($000s)

	2019	2020 Actual	2021	2022 Forecast	2023 Test Year
Income Tax Expense	410	352	275	72	(327)

2. Northland continues to use the flow through method in calculating income tax expense. Under the flow through method, Northland calculates the income tax expense based on taxable income which is minimized by claiming the maximum of all available deductions including Capital Cost Allowance (CCA). Northland also does not record deferred taxes under this methodology.

3. The 2023 Income Tax forecast is lower than 2022 mainly due to the Hay River Disposition as well as the higher CCA deduction in 2023 related to the CIS capital addition. This deduction will not be available in future years.

Income Tax Rate Variance Deferral Account

4. Income taxes forecast by Northland in this Application are based on the currently enacted Federal and Territorial statutory income tax and CCA rates.

5. As there is potential for these tax rates to change, Northland is requesting approval for the continued use of an income tax rate variance deferral account. Any changes from these rates will be used to determine an updated revenue requirement. This updated revenue requirement will be compared to the final Board-approved revenue requirement for the year in question and any difference will be either refunded to, or collected from, customers.

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Section 9 – Taxes Other Than Income

1. As Northland no longer operates in tax-based communities for the Test Year, any costs associated with taxes other than income have been included in Section 5.

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Section 10 – Other Revenues

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Section 11 - Capital Additions

Overview

1. The capital expenditures and additions included in this Application are outlined in Schedule 11.8 and are set out in the following table.

Table 11-1 – Capital Expenditures and Additions
($000s)

	2019	2020	2021	2022	2023
	Actual			Forecast	Test Year
Capital Expenditures	695	771	935	1,463	2,624
Capital Additions to Rate Base	674	695	861	1,089	1,470

2. The capital additions are broken down into the categories set out below.

Generation

3. Generation assets are continually monitored through power plant inspections and testing. Components are repaired or replaced in accordance with manufacturer specifications. The reliability and integrity of the power generation system is a key consideration when critical replacement decisions are being contemplated. Growth from the communities (load), premature failure, safety requirements, community-identified needs, obsolescence and environmental regulations can dictate the need for additional generation assets to be put in place.

Transmission

4. Transmission assets are inspected through line patrols which Northland conducts twice per year. From those inspections, assets that require replacement due to age and deterioration are identified. Northland is continuing its Pole Test and Treat Program to identify poles that have reached the end of their useful life cycle or present an immediate risk to the public or Northland's operational staff.

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New Extensions

5. Northland develops its new extension capital forecast based on discussions with communities, developers, engineering firms, and customers, in addition to known areas of development within its service area. Northland assesses the ability of the existing infrastructure to accommodate the proposed growth, taking into account the specific service requirements of the customer. An estimate is developed for the facilities required for the new extension and inserted into the forecast. In addition, Northland considers historical customer additions to account for walk-in customers that inevitably will require service.

6. Based on known activity in the remaining communities, Northland forecasts minimal new extensions in the 2023 Test Year.

Distribution Improvements

7. Distribution improvement projects fall into four major categories:

   i. System Performance Projects – are required to maintain system performance at an acceptable level. This category includes system protection, voltage, current and line clearance projects.

   ii. Life Extension Projects – are required to increase the life cycle of the distribution system. This category includes new feeder installations and streetlight upgrades.

   iii. System Replacement Projects – are required to replace distribution system facilities on a planned basis when they have reached the end of their life cycle. This includes replacement of overhead/underground system and equipment.

iv. Forced Projects – are required to correct unplanned system failures and line relocates where customers or government agencies request the relocation of the distribution facilities or where no easements exist.

8. In addition to the above, Northland tracks distribution system performance on an ongoing basis and the performance is reviewed when preparing the capital forecast.

9. Northland reviews unplanned outages that may be attributed to system deficiencies.

10. Northland reviews the options that are available to correct a problem and seeks engineering input to determine the most effective way to complete the required work.

11. Northland works closely with each of its communities and completes much of its work in conjunction with the community's road works program. Working together with the communities has proven to be efficient and cost effective when improvements to the electrical system are required.

12. Northland is not forecasting any planned distribution improvements in the 2023 Test Year.

Street and Sentinel Lights

13. Expenditures are required to provide street and sentinel lighting in Northland's service area. Streetlights that require replacement due to age and obsolescence are included in this category. New installations or requests from customers and developers are also included. All streetlight work is completed in consultation with the communities. The forecast is determined based on known areas of development in the communities, the results of streetlight audits, as well as a review of historic replacement requirements.

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Meters

14. Expenditures are required to upgrade from discontinued mechanical meters to electronic meters and to install new meters to accommodate load growth associated with customer requests for service. These expenditures allow Northland to meet its obligation to provide metered service connections. New meter additions are forecast based on known areas of development and expected connection requests.

15. Northland is not forecasting any planned meter replacements in the 2023 Test Year.

Transformers and Regulators

16. Distribution transformers are required to meet customer growth and to replace spare transformers that are being used for new extensions or for service upgrades.

17. Northland is not forecasting any planned transformer purchases in the 2023 Test Year.

General Plant and Equipment

18. This portion of the capital forecast provides for replacement of equipment and for the purchase of new equipment required to support the utility's operations. These include tools, office furniture, office computer equipment, software, communication equipment, transportation equipment and lands & buildings.

19. Northland follows a similar process to that indicated under Distribution Improvements to identify and justify expenditures in this area.

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Section 12 – Affiliate Transactions

1. Please refer to Section 5 for Related Party Transactions.

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Section 13 – Prior Board Directions

Summary

1. The following provides a response to prior Board Directions.

Board Directions

2014-2015 GRA Phase II: Board Decision 1-2016 (Dated February 29, 2016)[1]

	Direction	Response
4	The Board notes that under the NWT Utilities Minimum Filing Requirements approved in Decision 13-2014, details of costs at the account level, by zone, are required to be provided by NUL at the time of its next GRA. In the Board's view this information ought to facilitate examination of costs that have been directly assigned as well as those that have been allocated to rate zones, at the account level. The Board expects the account level information including basis of allocation or assignment of costs at the account level, to be reflected in future cost of service studies and supporting schedules. *(paragraph #60)*	Please refer to Schedule 5.1
10	In order to meet the requirements in GNWT Instruction 5a) that costs associated with Net Metering should be transparent and should be tracked by utilities and reported through the Board to the GNWT and, in order to calculate and account for the revenue loss arising from net metering, NUL is directed as follows: a) File an annual report within 90 days of each year end, commencing with 2015, a calculation of on-site generation in the following format: Annual Report On net Metering Customers Customer # | Customer Class | Type of Customer | Location | Size of Installation | Date Installed | Net Energy Export/Import kWh | Customer's on-site use kWh | Total on site Generation A | B | C | D | E | F | G | H | I Col A: Customer Identification #-no requirement to disclose confidential information Col B: The rate class to which the customer belongs Col C: Whether the customer is an individual, community organization, commercial entity etc Col D: Name of Community Col E: Number of kW installed Col F: Commissioning date Col G: net energy=Export Energy Minus Import Energy Col H: Estimated or metered on-site consumption by customer Col I: Energy used for subsidy calculations=Col G plus Col H b) File an annual calculation within 90 days of each year end, commencing with 2015, of lost revenues arising from net metering and the accounting thereof: i) Calculate loss of revenue (gross) using on-site generation times the supply rate for that customer's rate class and zone; on-site generation equals on-site customer use (from estimated or	The cumulative lost revenue from 2015-2021 is $51,841. Northland has assigned this balance based on location of solar installations. This amount will be directly assigned to communities according to the location of the net metering customer.

[1] Northland Utilities (NWT) Limited 2014-2015 GRA – Phase II.

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	metered on-site generation) ± net export within annual netting period; ii) Include the loss of revenue calculated in i) as part of sales revenue with the corresponding amount included in a deferral account to be disposed of in accordance with the paragraphs that follow. c) Disposition of deferral account: i) If accumulated lost revenue is below 1% of the actual annual earnings for the year, NUL may apply to recover lost revenue from customers in NUL's next Phase I GRA. ii) If accumulated lost revenue exceeds the 1% of the actual annual earnings threshold NUL may apply to the Board for approval to recover the excess over the 1% threshold by way of GNWT subsidies at the time of the next GRA or when the excess reaches a value of $10,000 whichever event is the earlier. *(paragraph #111)*	

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Section 14 – Supplemental Information

Revenue Requirement Including Town of Hay River

Overview

1. For purposes of aiding the Board with reviewing the impact on Revenue Requirement and Rates related to the Hay River Disposition, Northland has prepared Revenue Requirement calculations for the 2023 Test Year that, in addition to the Diesel communities, include the Town of Hay River. This Revenue Requirement calculation essentially represents a 'Status Quo' scenario, as though the Town of Hay River were to remain with Northland. Within the Status Quo scenario, Northland has capitalized legal fees incurred in connection with the Franchise Agreement process. The legal fees are assumed to be amortized over a 10-year term, which is consistent with the treatment of legal fees associated with renewal of the previous Franchise Agreement. The impacts of amortizing these fees are included in the capital additions, depreciation, and return on rate base sections below.

2. The tariffs and revenue requirement amounts associated with the Status Quo scenario are detailed in Section 14 Attachment 1, Schedules 2.0, 2.1, 3.0 and 3.1. Table 14-1 below, compares Northland's proposed Revenue Requirement Rate Impacts, as set out in Section 1 (i.e., Revenue Requirement excluding the Town of Hay River), and Revenue Requirement Rate Impacts, including the Town of Hay River (Status Quo):

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Table 14-1 – 2023 Revenue Requirement Rate Impacts %

	Section 14 w Hay River Rate Impacts	Section 1 w/o Hay River Rate Impacts	Difference
Thermal Zone	-17%	-12%	-5%
Hydro Zone [1]	4%	2%	2%
Total Company	**-2%**	**-9%**	**7%**

Note 1:
Please note that the Hydro Zone Rate Impacts from Section 1 (without HR as proposed) exclude any impacts to Hay River following the disposition and the implications of the disposition outlined in Section 1B of the Application.

Sales and Revenue

3. The Sales and Revenue forecast for the Status Quo scenario has been performed using the previously approved methodology as described in Section 2 of the Application. The energy sales and corresponding revenue based on the Status Quo scenario are provided in Section 14 Attachment 1, Schedule 2.1. Tables 14-2, 14-3 and 14-4 provide a breakdown of the Status Quo scenario by summarizing Energy Sales by Customer Class and by Area.

Table 14-2 – Northland Energy Sales by Customer Class (MWh)

	2022 Forecast	2023 w/Hay River	2023 w/o Hay River	Difference
Customer Class				
Residential	11,790	11,338	2,890	8,448
Commercial	20,457	21,546	3,240	18,306
Streetlights	547	547	135	412
Sentinel Lights	194	194	50	144
Total Company	**32,988**	**33,624**	**6,315**	**27,309**

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Table 14-3 – Residential Energy Sales by Area (MWh)

	2022	2023		
	Forecast	w/Hay River	w/o Hay River	Difference
Hay River	8,825	8,448	-	8,448
Remaining Hydro	1,033	1,013	1,013	-
Thermal	1,932	1,877	1,877	-
Total	**11,790**	**11,338**	**2,890**	**8,448**

Table 14-4 – Commercial Energy Sales by Area (MWh)

	2022	2023		
	Forecast	w/Hay River	w/o Hay River	Difference
Hay River	17,172	18,306	-	18,306
Remaining Hydro	1,261	1,274	1,274	-
Thermal	2,024	1,966	1,966	-
Total	**20,457**	**21,546**	**3,240**	**18,306**

Purchase Power

4. The Purchase Power included in the Status Quo is outlined in Section 14 Attachment 1, Schedule 4.3 and is set out in the following table.

Table 14-5 – Purchase Power ($000s)

	2022	2023		
	Forecast	w/Hay River	w/o Hay River	Difference
Purchase Power	3,565	3,877	307	3,570

5. When Hay River remains with Northland, Purchase Power increases by 8.75 percent, or $312,000, compared to forecast costs for 2022. Note the Purchase Power amount is for normal operations and approval for the deferral account related to increased diesel caused by the Taltson Hydro shutdown would still be required in this scenario.

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Diesel Fuel Costs

6. The Diesel Fuel costs included in the Status Quo are outlined in Section 14 Attachment 1, Schedule 4.1 and are set out in the following table.

Table 14-6 – Diesel Fuel Costs
($000s)

	2022	2023		
	Forecast	w/Hay River	w/o Hay River	Difference
Diesel Fuel Costs	2,618	2,308	1,932	376

7. The actual Diesel Fuel cost increase of $781,000 from 2019 to 2022 is mainly due to the increase in the price of diesel fuel. The forecast for the 2023 Test Year decreased by $310,000 mainly due to the duration of the plant shutdown in 2022.

8. Please refer to Section 14 Attachment 1, Schedule 4.1 for the details associated with the calculation of Diesel Fuel costs for 2019 to 2023.

Operations and Maintenance (O&M)

9. Total Operations and Maintenance (O&M) expenses and other taxes attributable to the Hay River Franchise included in the Status Quo, and as outlined in detail in Section 14 Attachment 1, Schedules 5.0 and 5.1, are set out as follows in the Table below.

Table 14-7 - Operations and Maintenance (O&M) Expenses
($000s)

Operations and Maintenance Expense		2022	2023		
		Forecast	w/Hay River	w/o Hay River	Difference
Production		1,055	992	727	265
Transmission		84	90	75	15
Distribution		1,355	1,342	421	921
General		40	32	31	1
Public Information		76	80	68	12

Operations and Maintenance Expense		2022	2023		
		Forecast	w/Hay River	w/o Hay River	Difference
Customer Accounting		424	413	174	239
Administration and General		1,402	1,416	1,024	392
Other Taxes		367	382	5	377
Less Donations		(14)	(10)	(10)	-
Total		**4,789**	**4,738**	**2,516**	**2,222**

10. In the above table Northland notes that the Administration and General costs do not reduce proportionally compared to other areas when comparing the two scenarios. This is a result of a significant portion of these costs being fixed (Audit Fees, Financial Services, etc.) as well as the labour requirement for safe and reliable services, further details are provided in Section 5 of this Application.

Depreciation

11. The Depreciation Expense included for the Status Quo, and outlined in Section 14 Attachment 1, Schedule 6.0, are as follows:

Table 14.8 – Depreciation Expense
($000s)

	2022	2023		
	Forecast	w/Hay River	w/o Hay River	Difference
Depreciation Expense	1,493	1,594	803	791

12. Consistent with the explanation provided in Section 6 of the Application, Northland is not applying any changes to previously approved depreciation rates or parameters for this scenario.

13. A portion of the increase in the 2023 depreciation expenses cost is a result of the treatment of the incurred legal fees because of the Hay River Disposition process. In the Status Quo scenario, these costs are amortized over the term of the Franchise Agreement, which is the same treatment that was applied to legal fees

incurred in connection with renewal of the previous Franchise Agreement. In the scenario without Hay River, these costs are included in the proposed deferral account.

Return on Rate Base

14. The Return on Rate Base for the Status Quo is outlined in Section 14 Attachment 1, Schedule 7.0, and is as follows:

Table 14-9 – Return on Rate Base
($000s)

	2022	2023		
	Forecast	w/Hay River	w/o Hay River	Difference
Return on Rate Base	820	860	514	346

15. The 2023 return on rate base is comparable to that of 2022 in the Status Quo scenario, with the slight difference mainly due to the Franchise Agreement legal fees that were capitalized.

Return on Equity (ROE) and Capital Structure

16. For the Status Quo, Return on Equity (ROE) has been applied consistent with the previously approved methodology as outlined in Section 7. Northland has set the ROE for the Test Year at the percentage determined on a generic basis for all Alberta Utilities for 2023, as determined by the Alberta Utilities Commission (AUC) in the 2023 Alberta Generic Cost of Capital Proceeding (2023 GCOC proceeding),[1] plus a risk premium of 0.35 percent. Northland has used the approved risk premium of 0.35 percent for illustrative purposes.

[1] Decision 27084-D01-2020.

17. Consistent with the rationale outlined in Section 7 of the Application, Northland is not requesting a change to the approved common equity adder of five percent for the Status Quo.

Capital Additions

18. The capital expenditures and additions included in the Status Quo are outlined in Section 14 Attachment 1, Schedule 11.8 and are set out in the following Table:

Table 14-10 – Capital Expenditures and Additions ($000s)

	2022	2023		
	Forecast	w/Hay River	w/o Hay River	Difference
Capital Expenditures	1,463	2,624	2,624	-
Capital Additions to Rate Base	1,089	1,990	1,470	520

19. Due to the immaterial amount of anticipated capital expenditures and additions related to Hay River, Northland has no additional capital additions included for this scenario.

20. As noted in the depreciation section above, only the legal fees related to the Hay River Disposition have been included in additions in the Status Quo scenario in the test period and are amortized over 10-years.

Distribution Rate and Rider Adjustments

21. Northland has updated the Rider calculations for the Status Quo. Northland is not requesting to implement these rates and has provided these calculations for illustration purposes. Please refer to Section 14 Attachment 1, Schedules 15.1 to 15.3 for the updated Rider calculations.

22. Northland has calculated rider deferral balances as of December 31, 2022 and has estimated the rate impacts for the Status Quo.

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23. The Rider A Fuel Cost Adjustment Rider has been updated per Section 14 Attachment 1, Schedule 15.2 to reflect a change in the Rider A rate, which was implemented effective November 1, 2022, after Northland's original 2023 GRA was submitted in September 2022.

24. The impact of the Rider changes on a sample Residential and Commercial customer's monthly bill for the Status Quo, with Hay River included in the Rider calculations, has been determined for each rate Zone in the following table.

Table 14-11 – Impact on Customers' Bills by Rate Zone

Zone/Rate Class	w/Hay River	w/o Hay River	Difference
[1]**Hydro Residential**			
[2]Non-Government %	+0.5%	+0.3%	+0.2%
[2]Non-Government $	$0.98	$0.52	$0.46
Government %	-2.1%	-5.1%	+3.0%
Government $	($4.92)	($12.12)	$7.20
[3]**Hydro General Service**			
Non-Gov & Gov %	-4.0%	-7.1%	+3.1%
Non-Gov & Gov $	($12.66)	($22.53)	$9.87
Thermal Residential[1]			
[2]Non-Government %	+0.4%	+0.4%	-0.1%
[2]Non-Government $	$0.76	$0.92	($0.16)
Government %	+4.1%	+13.2%	-9.1%
Government $	$21.17	$68.35	($47.18)
[3]**Thermal General Service**			
[2]Non-Government %	+0.0%	+0.0%	+0.0%
[2]Non-Government $	$0.0	$0.0	$0.0
Government %	+4.0%	+13.6%	-9.6%
Government $	$30.40	$102.67	($72.27)

Notes

[1] Residential customer using 600kWh per month

[2] For Non-Government Customers:
Residential includes GREP (Thermal Zone only) and TPSP
General Service includes GREP (Thermal Zone only)

[3] General Service customer using 1000kWh & 5kW per month

25. As evident from Table 14-11 above, not all customers are better served from the Disposition of the Town of Hay River. Namely, while customer's bills in the Hydro

zone increase when Hay River is included in revenue requirement (this comparison does not reflect the potential impact to Hay River customers following the disposition), customer's bills in the Thermal zone decrease when Hay River is included in revenue requirement at a higher magnitude of dollars for many customer classes.

Revenue Requirement Reconciliation

26. To assist the Board in reviewing the impacts on revenues and costs, Northland has provided a Revenue Requirement comparison by Zone for scenarios with and without Hay River. Northland has also provided explanations for the Thermal zone differences to illustrate the impact on revenue requirement when the Town of Hay River is excluded and when the Town of Hay River is included.

27. With the removal of the Town of Hay River, there is a significant reduction in the Revenue Requirement for the Hydro zone. This reduction is partially offset by the Transmission Revenue impact, as discussed in Section 1B. In addition, Northland has included in the Status Quo scenario legal fees incurred for the Hay River Disposition as these costs are prudently incurred costs associated with maintaining the Hay River Franchise regardless of service provider. These costs have been included in Rate Base and amortized over a 10-year period.

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Table 14-12 – Hydro Zone Difference with/without Hay River Revenues

Description	Hydro Zone w/Hay River 2023	Hydro Zone w/o Hay River 2023	Difference
Revenues			
Retail Revenues	8,726	782	7,944
Other Revenue	170	21	149
Transmission Revenue	-	1,111	(1,111)
Total Revenues	8,896	1,914	6,982
Costs			
Purchase Power	3,877	307	3,570
Diesel Fuel	376	-	376
Operations and Maintenance	3,805	1,283	2,522
Depreciation	1,161	370	791
Amortization of Contributions	(94)	(41)	(53)
Amortization of Deferred Costs/Credits	(639)	(52)	(587)
Return on Rate Base	563	123	440
Income Taxes	(153)	(77)	(76)
Total Costs	8,896	1,914	6,982

Table 14-13 – Thermal Zone Difference with/without Hay River Revenues

Description	Thermal Zone w/Hay River 2023	Thermal Zone w/o Hay River 2023	Difference
Revenues			
Retail revenues	3,289	3,464	(176)
Other revenue	65	85	(20)
Total Revenues	3,354	3,549	(196)
Costs			
Diesel Fuel	1,932	1,932	-
Operations and maintenance	933	1,233	(300)
Depreciation	433	433	-
Amortization of contributions	(44)	(44)	-
Amortization of deferred costs/credits	(146)	(146)	-
Return on rate base	297	391	(94)
Income taxes	(51)	(250)	199
Total Costs	3,354	3,549	(195)

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28. Please refer to the explanations below for the Thermal Zone differences:

(a) Operations and Maintenance: The difference in Operations and Maintenance (O&M) amounts is mainly due to the impact of the approved allocation methodology. Northland has used a consistent allocation methodology based on energy usage in both scenarios (revenue requirements With and Without Hay River) for Administration and General (A&G) costs. As the Thermal Zone has relatively less energy usage, the allocated A&G costs for the Thermal Zone are lower when combined with Hay River.

Similarly, Northland used a consistent allocation mechanism in both scenarios for allocating customer accounting and billing costs based on number of customers. As the Thermal Zone has relatively less customers, the allocated customer accounting and billing costs are lower for the Thermal zone when combined with Hay River.

(b) Return on Rate Base: The difference in the Return on Rate Base is mainly a result of the allocation methods for ATCO's Customer Information System (CIS) replacement program and working capital amounts. For the CIS replacement program, the costs have been allocated based on the number of customers and Working Capital costs have been allocated based on PP&E. As the Thermal Zone has relatively less customers and relatively less PP&E, the allocated CIS Replacement Program costs and working capital amounts are lower for the Thermal Zone when combined with Hay River.

(c) Income Taxes: The difference in income tax amounts is driven by the tax deductions related to the CIS replacement program as they are allocated based on the number of customers, as well as the changes in O&M amounts as described above.

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A NU and ATCO Company

Conclusion:

29. Northland has presented the above Status Quo scenario to aid the Board with reviewing the impact on Revenue Requirement and Rates related to the Hay River Disposition additional details can be found in Section 14 Attachment 1.

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Section 14 - Attachment 1 - Schedules with Hay River

Filed as an Excel document only.

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Section 15 – Distribution Rate and Rider Adjustments

Background

1. As discussed in Section 1, the 2023 revenue requirement excludes operating and maintenance costs and other taxes attributable to the Hay River Franchise, effective January 1, 2023. Rate and rider adjustments are required to properly reflect the removal of Hay River Franchise Assets, effective January 1, 2023.

2. In this section, Northland is providing updates to deferral balances and estimated rates for the following:

    a. The Rate Adjustment Rider, Rider R;
    b. The Purchase Power Adjustment Rider, Rider F; and
    c. The Fuel Cost Adjustment Rider, Rider A.

3. Northland is proposing rider updates for remaining customers outside of Hay River. In Hay River, Northland will leave the currently approved riders as-is for any time where Northland operates the Hay River assets beyond January 1, 2023, within reason.[1] Any balances will be distributed to the Town of Hay River at the time of transition.

4. All balances will be trued-up and finalized at the time of the Compliance Filing.

5. Updated Price Schedules are included in Attachment 1 - Rider Schedules.

Riders for Remaining Customers

Rate Adjustment Rider (Rider R)

6. As outlined in Section 1, Northland is seeking interim refundable approval for the proposed rate increase via the Rate Adjustment Rider – Rider R – applicable to each rate class within Northland's remaining communities in each zone, effective

[1] Northland will endeavor to manage deferral account balances appropriately and, if needed, will seek Board approval for any required changes to riders for Hay River.

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May 1, 2023. To implement Rider R by this effective date, Northland requires Board approval by April 21, 2023. Adjustments, if any, to final rates will be made to Rider R in the Compliance Filing to this Application.

7. Rider R will recover the 2023 revenue requirement shortfall by zone. The revenue requirement shortfall is the difference between the forecast 2023 revenue requirement and the forecast 2023 revenue from existing rates. In this Application, Rider R has been designed to collect the 2023 revenue requirement shortfall in each zone, by setting the rider to 2.30 percent in the Hydro Zone, and 9.20 percent in the Thermal Zone. The detailed derivations of Rider R can be found in Schedule 15.1.

Fuel Cost Adjustment Rider (Rider A)

8. Rider A refunds or recovers amounts that are tracked in two deferrals: 1) the Diesel Fuel Price Variance deferral; and 2) the Hay River Diesel Generation Variance deferral.

9. The Diesel Fuel Price Variance component of Rider A records variances between Board approved fuel prices and actual fuel prices. From 2023 going forward, this deferral account will be based on community-specific plant information in the Thermal Zone (shown in Schedule 4.1).

10. Considering the Hay River Disposition includes the generating assets, Northland will no longer incorporate the Diesel Generation Variance deferral in the Rider A balance for remaining customers beyond 2022. Accordingly, Northland is also proposing to finalize Rider A for remaining customers in the Hydro Zone and exclude these customers from Rider A going forward after any residual balance is depleted.

11. Finally, Northland proposes to decrease the threshold from +/- $220,000 to +/- $80,000 to trigger changes to the Rider A Rate This translates to approximately

two percent of the 2023 revenue requirement for remaining Thermal Zone communities.

12. Refer to Schedule 15.2 for the deferral balance estimate and proposed Rider A rates, effective May 1, 2023. Also, please note that Rider A has been revised from the original GRA filed in September 2022, due to a change in Rider A, effective November 1, 2022.

Purchase Power Adjustment Rider (Rider F)

13. Consistent with past approvals, Rider F is used to flow-through costs related to wholesale rate changes in the Hydro Rate Zone which are tracked in the associated Purchase Power Flow Through deferral account.

14. Due to the uncertain timing of the Hay River Disposition, Northland is proposing to use Rider F to recover the ongoing difference between forecast and actual Transmission losses and station service amounts between January 1, 2023, and the Hay River Disposition. Eventually, Northland expects a Distribution Wholesale rate to be available at points where its remaining Hydro Zone customers are connected to the Hay River distribution system, forgoing the need for station service energy and transmission losses to be included in its revenue requirement (as reflected in Schedule 4.1). Once a Distribution Wholesale rate is available, Northland expects to remove this component from Rider F.

15. The estimated Rider F for Northland's remaining customers (excluding Hay River) in the Hydro Zone, effective May 1, 2023, is shown in Schedule 15.3.

Impact to Remaining Customers' Bills

16. The impact of the proposed rider changes on sample residential and commercial customer monthly bills has been determined for each rate zone. An average monthly consumption of 600 kWh has been used for a sample residential customer and 1,000 kWh consumption and 5 kW demand for a sample general service

customer. The changes reported in the table include the impacts, as applicable, of the GNWT Rate Equalization Program (GREP) and the Territorial Power Subsidy Program (TPSP) for non-government residential and commercial customers.

Table 15-1 – Impact on Remaining Customers' Bills by Rate Zone

Rate Class	Hydro Zone		Thermal Zone	
	($)	(%)	($)	(%)
Residential[1]				
Non-Government[2]	$0.52	+0.3%	$0.92	+0.4%
Government	($12.12)	-5.1%	$68.35	+13.2%
General Service[3]				
Non-Government	($22.53)	-7.1%	$0.00	+0.0%
Government	($22.53)	-7.1%	$102.67	+13.6%

Notes

[1] Residential customer using 600kWh per month

[2] For Non-Government Customers:
Residential includes GREP (Thermal Zone only) and TPSP
General Service includes GREP (Thermal Zone only)

[3] General Service customer using 1000kWh & 5kW per month

For Hay River Customers

Rate Adjustment Rider (Rider R)

17. The currently approved Rider R will remain in place for Hay River during any period where Northland owns and operates the Franchise Assets beyond January 1, 2023. Any residual balance in this account will be trued-up upon transition of the Franchise Assets to the Town.

Fuel Cost Adjustment Rider (Rider A)

18. As discussed in Section 4, Northland proposes to continue to use the Hay River Diesel Generation Variance deferral to record variances between actual and forecast fuel and O&M costs associated with operating the Hay River generation facilities that are greater to or less than an approved percentage of total supply. This balance, along with any residual fuel price variance amounts, will be trued-up at the time of transition of the Franchise Assets to the Town.

Purchase Power Adjustment Rider (Rider F)

19. For customers in Hay River, the existing Rider F will remain for any period of time where Northland owns and operates the Franchise Assets beyond January 1, 2023, and the existing NTPC Wholesale Rate remains unchanged. Any residual amount in the Rider F balance for customers in Hay River will be trued-up at the time of transition to the Town.

Summary of Riders

20. Please refer to the following table which outlines applied-for riders for remaining customers and Hay River customers effective May 1, 2023.

Table 15-2 – Summary of Riders

	R: Rate adjustment			A: Fuel Cost Adjustment			F: Purchase Power	
Community	Hay River	Hydro	Thermal	Hay River	Hydro	Thermal	Hay River	Hydro
Hay River	-0.52%			$0.0366			$0.0244	
Enterprise		2.30%			$0.0224			$0.0069
K'atl'odeeche		2.30%			$0.0224			$0.0069
Dory Point			9.20%			$0.0658		
Fort Providence								
Wekweeti								
Sambaa K'e								

Section 15
Attachment 1

Effective: 2023-05-01
Supersedes: 2022-11-01

NORTHLAND UTILITIES (NWT) LIMITED
An ATCO Company

RIDER A
FUEL COST ADJUSTMENT

Available

- Throughout Northland Utilities (NWT) Ltd. service area.

Applicable

- To all classes of service

Rates

- This Rider is used to collect/(refund):
    - Fuel price variances between actual fuel costs and fuel costs based on the Board approved diesel prices included in base rates.
- Service will be rendered at the available rates with the following surcharge or (refund) relating to the cost of fuel.

Hydro Zone	$0.0224 / kWh
Thermal Zone	$0.0658 / kWh
Hay River	$0.0366 / kWh

Section 15
Attachment 1

Effective: 2023-05-01
Supersedes: 2022-06-01

NORTHLAND UTILITIES (NWT) LIMITED
An ***ATCO*** Company

RIDER F
PURCHASE POWER COST ADJUSTMENT

Available

- Within the Northland Utilities (NWT) Ltd, Hydro Rate Zone.

Applicable

- To all classes of service.

Rate

- A surcharge will be applied to all energy consumption for bills issued
- Rider F is required to flow through the costs related to wholesale rate changes in the Hydro Rate Zone.

Hydro Zone	$0.0069 / kWh
Hay River	$0.0244 / kWh

Section 15
Attachment 1

Effective: 2023-05-01
Supersedes: 2022-06-01

NORTHLAND UTILITIES (NWT) LIMITED
An ATCO Company

RIDER R
RATE ADJUSTMENT RIDER

Available

- Throughout Northland Utilities (NWT) Ltd. service area.

Applicable

- To all classes of service.

Rates

- This Rider is applied to base rates to collect or (refund) the difference between the revenue requirement and approved base rates.
- All of the company's base rate revenue will be adjusted by the following rates:

Hydro Zone	2.30 %
Thermal Zone	9.20 %
Hay River	-0.52 %

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Section 16 – Business Cases

1. Business Cases are provided for all projects greater than $100,000 in accordance with the negotiated settlement approved in Decision 17-2011.

2. The Business Cases fall into the following three categories:

   I. Not Filed in Previous Rate Applications – these projects have been completed since the last rate Application.

Number	Name
1	McBryan Drive Upgrade
2	Hay River Underground Cable Replacement
3	Hay River Pole Replacement
4	Portable Emergency Generator
6	Hay River CUL 197 Overhaul
7	Fort Providence CUL 570 Overhaul
8	2021 Pole Test and Treat
10	Sambaa K'e CUL 411 Replacement

   II. 2023 Capital Business Cases – these projects will be completed and added to rate base in the Test Year.

Number	Name
5	6L10 Pole Replacement
9	ATCO CIS Replacement
13	Fort Providence CUL 570 Replacement

   III. 2024 Capital Business Cases – Northland is seeking a project permit for the following two projects in 2024, consistent with Section 54 of the *PUA* which states:

> **54**. (1) A public utility shall apply to the Board for a project permit before undertaking a capital project having a total cost projected to exceed (a) $5,000,000, or ***(b) 10% of the utility's rate base. [emphasis]***

Number	Name
11	Saamba K'e Plant Move
12	Pine Point Transmission Transformer Replacement

Northland Utilities (NWT) Limited

2023 Amended General Rate Application (GRA)

McBryan Drive Upgrade

Business Case #01

Northland Utilities
A NU and ATCO Company

Executive Summary

Replace a section of underground power cable that has reached end of life and upgrade infrastructure during road works in the area.

Background

The Town of Hay River is replacing the water and sewer in the area, and the cables are end of life (originally installed in 1970). Replacing the cables, will bring them up to current standards thereby improving safety and reliability.

Project Description

Replace a section of underground power cable, install cable conduit, two overhead transformers with underground transformers and add new primary cable. The work will be completed during the replacement of the water and sewer systems in this area. Northland will work closely with the Town's contractor and engineering group to coordinate and complete this install.

Project Schedule

2015 - $713,000

Business Drivers and Benefits

The business drivers and benefits of the McBryan Drive Upgrade are as follows:

- Northland has an obligation to provide safe and reliable electricity service to customers, including minimizing unplanned outages.
- By completing the install in conjunction with the Town's work, Northland will not be required to dig up and replace roadways, pavement, sidewalks and/or customer driveways, as the work will align with the water and sewer replacement.

- Planning and scheduling the replacement allows Northland to reduce the number of outages that occur in unfavourable conditions and ensure that it has materials and equipment available to complete the work.

- Aligning with the water and sewer system replacement results in cost savings and minimizes disruption to customers in the area.

Evaluation of Viable Alternatives

Alternative 1 - Do nothing. This impacts the reliability of the system as the cables have reached end of life. This alternative presents the greatest disruption to customers in the near future (i.e., digging up roads again if work is not aligned with the water and sewer replacement) and forgoes any savings from aligning work with the Town.

Alternative 2 - Replace underground cables and upgrade to current standards as part of a planned project. This alternative ensures the reliability of the system based on known issues and the age of the infrastructure to prevent future outages, and allows Northland to complete the work most efficiently. In addition, the new line will meet current standards allowing for future load growth in that area.

Recommendation

Replace underground cables and upgrade to current standards.

Northland Utilities (NWT) Limited

2023 Amended General Rate Application (GRA)

Hay River Underground Cable Replacement

Business Case #02

Northland Utilities
A NU and ATCO Company

Executive Summary

Replace a section of underground power cable on Riverview Drive that has reached end of life, and where repeated failures have occurred.

Background

In this area, other cables have previously failed and have had to be replaced under undesirable circumstances, such as unplanned outages in winter. Due to the congested nature of the area, and other underground facilities, extensive hydrovac truck use is required to expose cables for replacement. The first portion of the section has already been replaced due to a fault, and this section was identified as the next priority due to the age and install date of the cables. This section of cable is part of Northland's underground loop that serves the schools, sewer lift station and downtown core.

Project Description

Replace a section of underground power cable.

Project Schedule

2017 - $178,383

Business Drivers and Benefits

The business drivers and benefits of the Hay River Underground Cable Replacement are as follows:

- Northland has an obligation to provide safe and reliable electricity service to customers, including minimizing unplanned outages.
- Portions of the cable have already failed and caused outages, indicating a need to replace cables in this area.

- Planning and scheduling the replacement allows Northland to prevent outages in unfavourable conditions and ensure that it has materials and equipment available to complete the work.

Evaluation of Viable Alternatives

Alternative 1 - Do nothing. This impacts the reliability of the system with failures occurring at any time and restoration being impacted based on conditions at the time of failure.

Alternative 2 - Replace underground cables as part of a planned project. This alternative ensures the reliability of the system based on a known issue and the age of the infrastructure to prevent future outages, and allows Northland to complete the work under ideal conditions. To ensure safety, availability of hydrovac truck and operator is key due to other underground infrastructure in the area.

Recommendation

Replace the underground cable.

Northland Utilities (NWT) Limited

2023 Amended General Rate Application (GRA)

Hay River Pole Replacement

Business Case #03

Northland Utilities
A NU and ATCO Company

Executive Summary

Replace poles in the community of Hay River as identified through pole testing, overhead line patrols, and damaged poles reported by third parties.

Background

In 2017, poles were replaced in the community of Hay River. Poles replaced were either determined to be end of life or had been damaged.

Project Description

Replace distribution poles.

Project Schedule

2017 - $119,092

Business Drivers and Benefits

The business drivers and benefits of the Hay River Pole Replacement are as follows:

- Northland has an obligation to provide safe and reliable electricity service to customers; and
- Replacing the poles that are at the end of their life or that have been damaged is essential to supplying power and avoiding unplanned outages due to structure failures.

Evaluation of Viable Alternatives

Alternative 1 - Do nothing. This alternative presents a safety risk to the public and causes unplanned power interruptions as poles failing increases due to the condition of the poles.

Alternative 2 - Replace poles identified as end of life or damaged. Ensure the safety and reliability of Northland's grid through required replacements.

Northland Utilities
A NI and ATCO Company

Recommendation

Replace poles identified as needed for replacement.

Northland Utilities (NWT) Limited

2023 Amended General Rate Application (GRA)

Portable Emergency Generator

Business Case #04

Northland Utilities
A NU and ATCO Company

Executive Summary

Purchase an emergency portable generator – Volvo TAD753GE 200 kW – to enable the restoration of communities served by Northland when an emergency outage arises at its isolated generation sites or radial distribution systems.

Background

The existing communities Northland serves can have longer timelines for restoration due to their isolation, distance from service points, and lack of available material for major repairs. The emergency portable generator is sized to serve Sambaa K'e, Wekweeti, Dory Point and part of Fort Providence. It is a self-contained unit with a fuel system, cooling, and switch gear. The portable unit is physically sized to fit into an aircraft for transfer to those communities.

Project Description

Purchase a Volvo TAD753GE 200 kW unit for emergency restoration.

Project Schedule

2017 - $113,399

Business Drivers and Benefits

The business drivers and benefits of Portable Emergency Generator are as follows:

- Northland has an obligation to provide safe and reliable electricity service to customers, including in the event of emergencies beyond its control.
- Enable restoration or partial restoration at plant sites or areas throughout the system where major restoration is required after an outage.
- Unit can be transferred to either community and/or left onsite for extended periods of time, if required.

Northland Utilities
A NU and ATCO Company

Evaluation of Viable Alternatives

Alternative 1 - Continue operating as is. In the event of an outage, power will be off for extended periods with few or no options to re-energize.

Alternative 2 - Purchase emergency generator. Based on the communities served, outages may occur such that generation is required. The emergency generator may also be required during cold weather to perform unplanned maintenance.

Recommendation

Purchase Emergency Generation unit.

Northland Utilities (NWT) Limited

2023 Amended General Rate Application (GRA)

6L10 Pole Replacement

Business Case #05

Northland Utilities
A NI and ATCO Company

Executive Summary

Several poles were identified for replacement following the 2021 Pole Test and Treat work on the Transmission Line 6L10 between the Pine Point Substation and Hay River Substation.

Background

After identifying poles that require replacement (due to end of life or damage), Northland will replace the poles on the 6L10 transmission line between Hay River and Pine Point in 2023.

Project Description

Replace poles on the 6L10 transmission line and impacted structures. Given the extent of the pole replacements required, the target for completion of this work is during the extended Taltson outage in 2023.

Project Schedule

2023 - $275,000

Business Drivers and Benefits

The business drivers and benefits of the 6L10 Pole Replacement are as follows:

- Northland has an obligation to provide safe and reliable electricity service to customers, including reliable transmission of electricity from the Taltson Hydro Electric System to customers in Hay River, K'atl'odeeche First Nation, and Enterprise.
- Limit the unplanned outages through regular capital maintenance to continue to operate the system without unknown structure failures.

Evaluation of Viable Alternatives

Alternative 1 - Do Nothing. This alternative presents a safety risk to the public and causes unplanned power interruptions as poles failing increases due to the condition of the poles.

The poles are also adjacent to the highway posing a safety risk to others.

Alternative 2 - Replace poles and complete structure repairs as identified in the 2021 Test and Treat Report. Ensure the safety and reliability of Northland's grid through required replacements.

Recommendation

Replace poles identified for replacement on 6L10, during the 2023 extended hydro shutdown.

Northland Utilities (NWT) Limited

2023 Amended General Rate Application (GRA)

Hay River CUL 197 Overhaul

Business Case #06

Northland Utilities
A NI and ATCO Company

Executive Summary

Major overhaul is required on unit CUL-197 in accordance with the manufacturer's recommended maintenance schedule. CUL-197 is a 1997 CAT 3512 800 kW unit and is required to supply electricity to the Town of Hay River and surrounding Hydro communities. It is essential that CUL-197 runs reliably and is available, when required, to provide uninterrupted electrical supply in the Town of Hay River and surrounding Hydro communities.

Background

CUL-197 was installed in 1997 and is used in combination with other units within the Hay River power plant to provide backup power to the Town of Hay River and surrounding communities when the NTPC hydro supply is not available.

Project Description

Engine components need to be replaced per the Original Equipment Manufacturer (OEM) maintenance schedule recommendations. During regular inspection of CUL-197, rainwater was found to have entered the engine through the exhaust system. An inspection of the unit was required to assess possible damage. The disassembly and inspection of the unit, as well as repairs required, were similar in nature to the upcoming scheduled major overhaul. To avoid duplicative work and expense, the major overhaul was required. Considering NTPC had a major 7-month shutdown scheduled for 2023, it is imperative to have all units available at the Hay River Power Plant.

Project Schedule

2021 - $219,631

Business Drivers and Benefits

The business drivers and benefits of the Hay River CUL 197 Overhaul are as follows:

- Northland has an obligation to provide safe and reliable electricity service to customers, which includes regular maintenance of its back-up generation systems.
- The overhaul of CUL-197 will ensure reliable and safe delivery of electricity to the customers of Hay River and surrounding areas when needed.
- Failure to complete the overhaul of unit CUL -197 could result in engine failure and the potential inability to meet the electrical requirements of the community.
- The overhaul will also reduce compounding damage that can affect other components of the engine.

Evaluation of Viable Alternatives

Alternative 1 - Do nothing and continue to run CUL-197 as is. This alternative is not practical or responsible as failing to replace and maintain components of the engine could result in failure of the engine and cause a disruption in service for the customers in Hay River and surrounding communities.

Alternative 2 - Replace the entire CUL-197 engine with a new engine. This alternative would be costly as the entire engine would be replaced rather than just certain components. This would also have the potential to impact and call for replacement of other systems within the plant (e.g. electric components).

Alternative 3 - Complete the overhaul of CUL-197 as per the manufacturer's recommendation. The overhaul will allow Northland's staff to complete an internal inspection of the engine while completing the overhaul of certain components. An overhaul of the existing engine ensures that other systems within the plant do not require upgrading of changing.

Recommendation

Complete the overhaul of CUL-197.

Northland Utilities (NWT) Limited

2023 Amended General Rate Application (GRA)

Fort Providence CUL 570 Overhaul

Business Case #07

Northland Utilities
A NI and ATCO Company

Executive Summary

CUL-570 required a top end overhaul due to coolant in the oil system. In addition, an overhaul was performed in accordance with the manufacturer's scheduled maintenance service.

Background

CUL-570 is a Cummins QSK23 725 kW unit and is required to supply electricity to the community of Fort Providence. It is essential that operation of CUL-570 is reliable and efficient, ensuring it can supply uninterrupted electrical supply in the community of Fort Providence. CUL-570 was installed in 2015 and is the largest of the four units that power Fort Providence.

Project Description

CUL-570 was showing signs of internal engine failure. Upon inspection by Northland, it was found that CUL-570 had coolant in the oil system. The unit was removed from service and shipped for further inspection and repair. A top end overhaul was required to repair the coolant in the oil system. While at the repair shop and disassembled, it was also identified that the unit would soon be due for a scheduled maintenance overhaul. Therefore, to avoid the duplicative expense of Northland receiving the repaired unit, and then sending it back again for the manufacturer's recommended engine overhaul, the engine overhaul was completed slightly ahead of schedule concurrent with the top end overhaul to repair coolant in the oil system.

Project Schedule

2017 - $213,589

Business Drivers and Benefits

The business drivers and benefits of the Fort Providence CUL-570 Overhaul are as follows:

- Northland has an obligation to provide safe, reliable supply of electricity, which includes maintenance of its back-up generation systems.
- The overhaul of CUL-570 will ensure reliable and safe delivery of electricity to the customers of Fort Providence.
- Failure to complete the overhaul of unit CUL-570 could result in engine failure and the potential inability to meet the electrical requirements of the community.
- The overhaul will also reduce compounding damage that can affect other components of the engine.

Evaluation of Viable Alternatives

Alternative 1 - Do nothing and continue to run CUL-570 as is. This alternative is not practical or responsible as failing to replace and maintain components of the engine could result in failure of the engine and cause a disruption in service for the customers in Fort Providence.

Alternative 2 - Replace the entire CUL-570 engine with a new engine. This alternative would be costly as the entire engine would be replaced rather than just certain components. This would also have the potential to impact and call for replacement of other systems within the plant (e.g., electric components).

Alternative 3 - Complete the major overhaul of CUL-570 as per the manufacturer's recommendation. The overhaul will allow Northland's staff to complete an internal inspection of the engine while completing the overhaul of certain components. An overhaul of the existing engine ensures that other systems within the plant do not require upgrading of changing.

Recommendation

Proceed with completing the overhaul of CUL-570.

Northland Utilities (NWT) Limited

2023 Amended General Rate Application (GRA)

2021 Pole Test and Treat

Business Case #08

Northland Utilities
A and Company

Executive Summary

Pole testing and treating is completed on a 9-year cycle throughout the system to assess the health and treat the poles to extend their lifecycle. The poles on Transmission Line 6L10 required testing and were originally scheduled to be tested and treated in 2020 and 2021, with half the poles on the line tested and treated in each year. However, due to the pandemic, no poles were tested or treated in 2020. As a result, all poles on 6L10 were tested and treated in 2021 to make up for the lost year due to the pandemic.

Background

Pole Test and Treat involves qualified professionals assessing and treating poles across Northland's system to protect them from decay and to extend their useful life. Test and treat were not performed in 2020 because of COVID-19 and the resulting border restrictions that were put in place. Therefore, the work was completed in 2021 for work that was previously scheduled to take place in 2020 and 2021.

Project Description

Pole Test and Treat Program for Transmission Line 6L10.

Project Schedule

2021 - $173,840

Business Drivers and Benefits

The business drivers and benefits of the Pole Test and Treat Program follow:

- Northland has an obligation to provide safe and reliable electricity service to customers.
- Testing and treating poles assist in ensuring a reliable transmission connection to the Hydroelectric system and reduces unplanned outages due to structure failures.

- Testing and treating identifies poles in need of replacement while simultaneously treating other poles to extend their useful life.

- Testing and treating is performed on a 9-year cycle to ensure the entire system is reviewed on a regular basis, and poles can be replaced as identified to prevent structure failures and unplanned outages. This work is undertaken in conjunction with overhead line patrols that ensure the safety and reliability of Northland's system.

Evaluation of Viable Alternatives

Alternative 1 - Complete test and treat on only half of the poles on the Transmission Line. This alternative limits the full understanding of the scope required to address any issues with poles on Transmission Line 6L10.

Alternative 2 – Catch-up for 2020 and complete the testing and treatment for the full Transmission Line in 2021. This alternative defines the full scope of work to be completed on the 6L10 Transmission Line with sufficient time to plan for this work to be completed during NTPC's extended Taltson Plant shutdown.

Recommendation

Complete full testing and treating for the entirety of the 6L10 Transmission Line in 2021.

Northland Utilities (NWT) Limited

2023 Amended General Rate Application (GRA)

ATCO CIS Replacement

Business Case #9

Northland Utilities
A and ATCO Company

Executive Summary

Lifecycle replacement of ATCO CIS with Oracle Customer Cloud Service solution (CSS) to mitigate risks associated with the current (end-of-life) system and to provide Northland with the right tools to perform customer care and billing (CC&B) in an accurate, reliable and efficient manner.

Background

ATCO CIS was built in the early 1990s and is an end-of-life asset. As a result, it is increasingly costly and difficult to maintain the underlying COBOL programming language as well as add functionality. In particular, the internal resources that understand the highly customized nature of ATCO CIS are beginning to retire, and the number of skilled COBOL programmers in the marketplace is decreasing. The combination of these effects contributes to the increasing costs to maintain and support ATCO CIS.

Furthermore, the cyber security risks increase with continued use of an antiquated system compared to modern software applications that are designed to minimize the ever-increasing risk of malicious attackers taking advantage of application vulnerabilities. Given that ATCO CIS enables critical business functions fundamental to Northland's regulated, integrated electric distribution business, the risk of not replacing ATCO CIS was too great.

In addition, Northland and its systems must be flexible, supportive, and responsive to increasing demands of electrification, including renewable technologies such as solar panels, as well as increasing the complexity of the billing systems. The replacement of the legacy ATCO CIS will allow Northland to continue to meet its billing requirements and ensure needs can be met into the future.

Project Description

The ATCO CIS system was built in the early 1990s and is used by the ATCO utilities, including Northland. Due to the age and highly customized functionality of ATCO CIS,

and consistent with the conclusion of a third-party report, it was determined that ATCO CIS posed too great of a business risk and should be replaced.[1] As a result, Northland conducted a procurement process to compare Oracle CCS against Tier 3 niche products available in the marketplace for fully integrated utilities that serve less than 100,000 customers. The evaluation confirmed Oracle CCS as the best alternative.

In addition to achieving the lowest cost option for customers, the goals of the project were: to maximize out-of-the-box functionality and minimize customization to facilitate lifecycle management, minimize future operating costs and risk, maintain a high level of customer care and billing service, support regulatory requirements, and reduce technology risk. Northland will, as required, utilize the specialist(s) within ATCO to support Oracle CCS and related functions, including vendor support and CCS updates.[2]

Resources Required

In general, resources will be staffed through a combination of internal ATCO business employees and contractors (i.e., direct labour). Northland also leveraged the expertise of TMG Consulting during the procurement process.

Project Schedule

2023 - $1,062,179

Business Drivers and Benefits

The business drivers and benefits of the ATCO CIS Replacement are as follows:

- ATCO CIS is a critical system relied upon to manage all aspects of the meter to cash cycle. Without a working and capable CIS, Northland would be unable to

[1] In Decision 26616-D01-2022, the Alberta Utilities Commission (AUC) approved CIS Replacement for the ATCO Distribution Utilities, paras 254, 261-262
[2] A Tier 3 niche solution would have required additional resources to support the billing Application unique to Northland.

accept new customers, manage customer moves, calculate usage and charges, bill customers or collect and manage revenue.

- Sudden or unexpected outages could have negative impacts on Northland's ability to maintain acceptable levels of CC&B and meet its obligation to serve.
- Existing CIS is end-of-life.
- Cybersecurity threats – modern software applications are designed to minimize the ability of attackers to take advantage of application vulnerabilities.
- Availability of resources – the number of skilled COBOL programmers in the marketplace is decreasing, creating a significant and growing skills gap. The number of experienced and qualified internal resources continues to decline as ATCO CIS ages.
- Ongoing internal support of existing CIS is disappearing as parent company no longer supports.
- The electricity industry is currently undergoing a transformation, including electrification (electric vehicles and Distributed Energy Resources), two-way communication between utilities and customers, and the better enablement of price signals through rate design such as time of use (TOU) rates.
- Oracle CCS was selected because of the high degree of functional fit with business requirements, technical compatibility and integration because Northland already utilizes Oracle Enterprise Resource Planning software.
- Finally, Oracle CCS is a subscription-based service. The latter helps maintain protection from cybersecurity threats.

Evaluation of Viable Alternatives

Alternative 1 – Status quo. NUL continues to operate ATCO CIS. This option is neither acceptable nor feasible given the business drivers identified above. The ATCO CIS system is end of life and requires replacement. In addition, no other ATCO utility will be using ATCO CIS beyond 2023.

Alternative 2 – Replace ATCO CIS with Oracle CCS. This option reduces the risk of a critical system failing and reduces cyber security threats. This option is the lowest cost alternative to customers, as Northlands will utilize the expertise gained from ATCO Utilities for both implementation and to perform CC&B services.

Alternative 3 – Replace ATCO CIS with Tier 3 COTS solution. This option reduces the risk of a critical system failing and reduces cyber security threats. However, this option is more costly as it requires specialized implementation resources and training to use the system (e.g. interface training, upgrades and maintenance).

Recommendation

ATCO CIS is end-of-life and requires replacement. Northland recommends proceeding with the replacement of ATCO CIS with Oracle CCS, as detailed in the sections above. The business risk associated with continued use of ATCO CIS is unacceptable. Replacing ATCO CIS with Oracle CCS is beneficial to Northland and its customers.

Northland Utilities (NWT) Limited

2023 Amended General Rate Application (GRA)

Sambaa K'e CUL 411 Replacement

Business Case #10

Northland Utilities
A NU and ATCO Company

Executive Summary

Replace CUL-411 engine with a 150 kW Volvo TWD733GE unit, in accordance with manufacturer's hours limit specifications. This unit is part of Northland's Sambaa K'e Power Plant that provides power to the community of Sambaa K'e.

Background

The existing engine CUL-411 was installed in 1996 and is a 150 kW Volvo TWD710G. Due to the age of the existing unit, there is no longer a reliable supply of parts and materials to service the engine. A new Volvo unit was purchased to replace CUL 411.

Project Description

Purchase and install the new 150 kW Volvo TWD 733 GE.

Project Schedule

2020 - $172,411

Business Drivers and Benefits

The business drivers and benefits of the Sambaa K'e CUL 411 Replacement are as follows:

- Northland has an obligation to provide safe and reliable electricity service to customers.
- Failure of this unit would hinder Northland's ability to supply power to the community of Sambaa K'e.
- Failure to replace the engine of CUL-411 could result in the unit's failure and the possible inability to meet the electrical requirements of the community.

Evaluation of Viable Alternatives

Alternative 1 – Do nothing and continue to run CUL-411 as is. This alternative is not practical or responsible as failing to replace and maintain components of the engine could result in failure of the engine and cause a disruption in service for the customers

Alternative 2 – Replace CUL-411 with a similar engine. As parts have become scarce and, in most cases, not available, replacement with a similar engine is most prudent and reduce the risk of unplanned outages. In addition, due to the location, a planned replacement ensures access to the remote community is planned and the unit is brought in on the available winter road and replaced during planned outages.

Alternative 3 – Undertake major overhaul on CUL-411. Materials have stopped being made available or produced by the manufacturer. Additional complications could result from the remote nature if parts end up not being compatible or not available during an emergency repair situation.

Recommendation

Proceed with the replacement of CUL-411 with a similar engine.

Northland Utilities (NWT) Limited

2023 Amended General Rate Application (GRA)

Sambaa K'e Plant Move

Business Case #11

Northland Utilities
A NI and ATCO Company

Executive Summary

Northland is proposing to relocate the existing powerplant to the outskirts of the town, driven by the expansion of the town near the facility and proximity of diesel storage to nearby lakes. The plant was installed in its current location in 1987, and the town has since grown around it, and it is now adjacent to the school and store. Relocating the plant also aligns with a request from the Community of Sambaa K'e to move it further away from the town.

The new location will be further away from the Town and nearby lakes. The project involves acquiring property, civil works construction (for fencing, grounding, etc.), oil storage support for the new site, moving the power plant, and reclamation of the current site.

Background

When the plant was first commissioned in 1987, the nearest building was a nearby maintenance shop which used the waste heat from the plant. In the years since the plant was installed, a school and store have been built adjacent to the plant. The existing powerplant is located 37 meters away from the elementary school's playground and roughly 50 meters away from the closest store. Please refer to Figure 1 below, which shows the proximity of the school and local businesses. In turn, noise and exhaust from the plant disrupt the surrounding community, which has ultimately led to a request from the community to relocate the plant.

Northland Utilities
A NI and ATCO Company

Figure 1 - Layout of Town Around Power Plant

This project involves consultation and agreement on a new site, construction of the new site, relocating the plant and reconnecting it to the grid, and reclaiming the existing site.

Project Description

Relocating the existing Diesel Power Plant feeding the community of Sambaa K'e. The project involves acquiring property, civil works for site prep, running temporary power from a standby plant, relocating the power plant, reconnecting the plant to the grid, testing, and reclaiming the current site.

Project Schedule

2024 - $1,232,570

Northland Utilities
A NI and ATCO Company

Business Drivers and Benefits

The main driver for this Project is the proximity of the Town to the existing powerplant location, due to the Town's growth. These new community centres are now exposed to noise, exhaust, and an operating generation plant. In addition, moving the plant eliminates the need for diesel storage in close proximity to water bodies and drainage ditches. Northland notes that while measures are being taken to reduce any environmental issues, as experienced in 2008, environmental concerns of the community persist due to the current location and have increased due to the proximity of the school and storefronts.

The benefit of this Project is that a new location would result in noise and exhaust reduction within the community and reduced environmental exposure. The move also aligns with the community's desire to relocate the power plant further away from Town. Northland is seeking a location at least 500 m away from Town.

Evaluation of Viable Alternatives

Alternative 1 – Keep the power plant in the same location. This alternative would continue to provide reliable service but does not address the continued noise and emissions from the plant in close proximity to the community centre, environmental concerns, and is not aligned with the community's request.

Alternative 2 - Relocate the plant to a new site away from the community centre. This is preferred by the customers and the community due to the environmental and societal benefits described above.

Alternative 3 – Decommission the existing plant and build a new power plant. A new power plant is expected to cost several million dollars and is not expected to be economically viable with the small customer base currently served by the power plant.

Recommendation

Proceed with relocating the plant (Alternative 2) and continue to work with the community to minimize disruption of the existing plant in the interim.

Northland Utilities (NWT) Limited

2023 Amended General Rate Application (GRA)

Pine Point Transmission Transformer Replacement

Business Case #12

Northland Utilities
A NU and ATCO Company

Executive Summary

The existing transformer at Pine Point Substation has reached end of life and is having issues with leaking that need to be addressed. Given the age of the transformer and the limited availability of replacement parts, it is recommended that the transformer be replaced instead of repaired.

Background

The transformer at the Pine Point Substation was originally built in 1968 and was leaking, which needed to be addressed. The transformer is a critical piece of infrastructure on the path to all downstream hydro communities in the Taltson Zone.

In 2016, Northland attempted a limited-impact repair to address the transformer leak, but it was not successful. To repair the existing transformer, radiators need to be removed and the oil needs to be reconditioned. The existing transformer has already exceeded the expected life span (typically, transformers of this style have a 40-year life span). Therefore, replacing the transformer is preferable to attempting to repair it again.

Project Description

Replacement of the Pine Point Substation transformer

Project Schedule

2024 – $1,885,000

Business Drivers and Benefits

The primary business drivers and benefits of the Pine Point Transmission Transformer are as follows:

- Northland has an obligation to provide safe and reliable electricity service to customers.

- Any failure of the transformer would constitute a major repair and would make the downstream communities rely on diesel generation. The resulting outage due to the loss of this transformer could be weeks in length (or longer).
- The existing transformer is at the end of its useful life.
- Replacing the transformer allows leaks to be addressed.

Evaluation of Viable Alternatives

Alternative 1 - Do nothing. As the asset is end of life, this will not address the impact on reliability, the increased use of back up diesel generation for any outage, and increased power costs based on fuel prices while the diesel generation is running, and the hydro power is not able to be distributed.

Alternative 2 - Remove the radiators to repair the leak and recondition the oil and clean up the released substances. The asset is end of life and does not address the risk of unplanned failure and outages. Previous attempts to fix the existing transformer were unsuccessful. Due to the unique characteristics of the transformer and remote location, costs to fully service, disassemble and reassemble the existing transformer would exceed costs to replace it.

Alternative 3 - Replace the existing transformer with a new transformer. This alternative allows Northland to plan and time the replacement with other work to minimize the need for diesel generation, as well as enhances the reliability of the substation to continue to provide power.

Recommendation

Replace the transformer with a new transformer.

Northland Utilities (NWT) Limited

2023 Amended General Rate Application (GRA)

Fort Providence CUL 570 Replacement

Business Case #13

Northland Utilities
A NU and ATCO Company

Executive Summary

Replace CUL-570 generation unit, which is a 725 kW unit that failed prior to the scheduled major overhaul in 2022, with a Cummins QSK23 725 kW unit.

Background

The existing engine CUL-570 failed prior to being removed and sent for a major overhaul. This unit is part of the plant that supports the community of Fort Providence for which all power is provided through diesel generation. The failure of the unit was caused by damage arising from valve contact with the piston, causing the valve to break off resulting in significant internal damage to the engine. CUL-570 has had a history of issues, despite keeping to manufactures maintenance schedules.

Project Description

The replacement for CUL-570 was installed in 2022.

Project Schedule

2022 - $150,000

Business Drivers and Benefits

The business drivers and benefits of the Fort Providence CUL 570 Replacement are as follows:

- Northland has an obligation to provide safe and reliable electricity service to customers.
- Failure of the current unit puts the safe and reliable supply of electricity to Fort Providence in jeopardy.

- Availability of a suitable replacement in a timely manner will ensure risk is limited in the event of other unexpected unit failures within the plant, and prior to the winter months when demand will be greater.

Evaluation of Viable Alternatives

Alternative 1 – Repair CUL-570 engine. This alternative is a higher cost option compared to replacement of the unit due to the major damaged discovered. The timeline to repair could further escalate and put the supply of electricity to Fort Providence at risk.

Alternative 2 – Replace CUL-570 with a similar engine. A new engine was less costly than a repair due to the major damage discovered. In addition, the manufacturer had a replacement engine available which could be installed to achieve stabilization of the plant on a predictable schedule and will ensure the reliable supply of electricity to the community.

Recommendation

Replace CUL-570 with a similar engine in 2022.

Canada Revenue Agency | Agence du revenu du Canada

Schedule 444
Code 2301
Protected B
when completed

Yukon Business Carbon Price Rebate (2023 and later tax years)

Corporation's name	Business number	Tax year-end Year Month Day

- You can claim the Yukon business carbon price rebate (which includes the general business carbon price rebate and the mining business carbon price rebate) under section 16 of the Yukon Income Tax Act, if **both** of the following conditions apply:
  - You are an eligible Yukon business taxpayer or an eligible Yukon mining business taxpayer
  - You used an eligible Yukon asset or an eligible Yukon mining asset in the tax year, principally in carrying on an eligible Yukon business or an eligible Yukon mining business
- The Yukon business carbon price rebate applies to an eligible Yukon business taxpayer and, for tax years ending after 2022, to an eligible Yukon mining business taxpayer.
- The Yukon mining business carbon price rebate is a refundable tax credit equal to the amount of the mining business rebate factor for the financial year in which the tax year ends multiplied by the eligible Yukon mining undepreciated capital cost (UCC) to the taxpayer as of the end of the tax year.
- The Yukon general business carbon price rebate is a refundable tax credit equal to the amount of the general business rebate factor for the financial year in which the tax year ends multiplied by the amount of the eligible Yukon UCC to the taxpayer as of the end of the tax year that exceeds the amount of the eligible Yukon mining UCC, if any, if you are an eligible Yukon mining business taxpayer.
- The terms **eligible Yukon business taxpayer**, **eligible Yukon mining business taxpayer**, **eligible Yukon asset**, **eligible Yukon mining asset**, **eligible Yukon UCC**, **eligible Yukon mining UCC**, **eligible Yukon business**, **eligible Yukon mining business**, and **cross-border transport equipment** are defined in subsection 16(1) of the Yukon Income Tax Act.
- To claim the Yukon business carbon price rebate, file a completed copy of this schedule with your T2 Corporation Income Tax Return.

Part 1 – Eligible Yukon mining UCC for eligible Yukon mining assets

Are you an eligible Yukon mining business taxpayer? . . . . . ☐ Yes ☐ No

If **yes**, complete Part 1.

If **no**, go to Part 4.

1 Class number of eligible Yukon mining asset [1]	2 Prescribed inclusion rate [2]	3 Prescribed fraction [3]	4 UCC at the end of the year (enter amount from line 220 of Schedule 8, Capital Cost Allowance, that relates to the eligible Yukon mining asset)	5 Capital cost allowance (enter amount from line 217 of Schedule 8, Capital Cost Allowance, that relates to the eligible Yukon mining asset)	6 Column 4 **plus** column 5	7 Eligible Yukon UCC at the end of the year for eligible Yukon mining assets (column 2 **multiplied** by column 3 **multiplied** by column 6)

Total _____ A

Eligible Yukon mining UCC

Amount A _____ × Prescribed mining adjustment factor [4] _____ = ... _____ B

Part 2 – Eligible Yukon mining UCC allocated from partnerships

Eligible Yukon mining UCC allocated from partnerships [5] . . . . . _____ C

Part 3 – Yukon mining business carbon price rebate

Total eligible Yukon mining UCC (amount B **plus** amount C) . . . . . _____ D

Yukon mining business carbon price rebate [6]

Amount D _____ × Mining business rebate factor [7] _____ = ... _____ E

Enter amount E on line 696 of Schedule 5, Tax Calculation Supplementary – Corporations.

Canada

Protected B
when completed

Part 4 – Eligible Yukon UCC for eligible Yukon assets

Include eligible Yukon mining assets (other than classes 41 and 41.2) in this part.

1 Class number of eligible Yukon asset [8] 200	2 Prescribed inclusion rate [9] 205	3 Prescribed fraction [3] 208	4 UCC at the end of the year (enter amount from line 220 of Schedule 8, Capital Cost Allowance, that relates to the eligible Yukon asset) 210	5 Capital cost allowance (enter amount from line 217 of Schedule 8, Capital Cost Allowance, that relates to the eligible Yukon asset) 215	6 Column 4 **plus** column 5	7 Eligible Yukon UCC at the end of the year (column 2 **multiplied** by column 3 **multiplied** by column 6) 220
				Total		F

Part 5 – Eligible Yukon UCC allocated from partnerships

Eligible Yukon UCC allocated from partnerships [10] . . . . . 320 _____

Part 6 – Yukon general business carbon price rebate

Total eligible Yukon UCC (amount F **plus** line 320) . . . . . _____ G

Total eligible Yukon mining UCC [11] . . . . . _____ H

Net eligible Yukon UCC (amount G **minus** amount H, if negative enter "0") . . . . . _____ I

Yukon general business carbon price rebate [6]

Amount I _____ × General business rebate factor [12] 500 _____ = ... _____ J

Enter amount J on line 699 of Schedule 5, Tax Calculation Supplementary – Corporations.

Notes

[1] The following classes are prescribed for the purposes of the definition **eligible Yukon mining asset**:

(a) Classes 1, 3, 10, 10.1, 13, 16, 22, 28, 29, 38, 39, 40, 41, 41.2, 43, and 53

(b) Classes 43.1, 43.2, 54, 55, and 56

The classes prescribed for the purposes of the definition **eligible Yukon mining asset** are subject to change.

Where the list of classes provided here differs from that provided in the Carbon Price Rebate General Regulation, the latter takes precedence.

[2] The inclusion rates for prescribed classes of eligible Yukon mining assets are:

(a) Classes 1, 3, 10, 10.1, 13, 16, 22, 28, 29, 38, 39, 40, 41, 41.2, 43, and 53: 100%

(b) Classes 43.1, 43.2, 54, 55, and 56: 500% **multiplied by** the general business rebate factor for the financial year in which the tax year ends **divided by** the mining business rebate factor for that financial year.

[3] If you don't use cross-border transport equipment, enter "1".

If you use cross-border transport equipment principally to transport passengers or goods from Yukon to outside Yukon, or you make an election under subsection 16(11) of the Yukon Income Tax Act, enter the prescribed fraction.

The prescribed fraction equals the net fuel quantity you used in Yukon for operating the cross-border transport equipment for the tax year, divided by the net fuel quantity you used worldwide (including in Yukon) in operating that equipment.

Enter a decimal number less than or equal to 1 with a maximum of two decimal places to express this fraction.

[4] If you carry on a specified placer mining business in the tax year and do not carry on a specified quartz mining business in the tax year, enter "4". If you carry on a specified quartz mining business in the tax year, enter "1".

[5] If you are a member of a partnership that is an eligible Yukon mining business partnership, the eligible Yukon mining UCC at the end of the year from the partnership is equal to your specified proportion of the eligible Yukon mining UCC to the partnership at the end of the partnership's fiscal period.

Enter the total of all eligible Yukon mining UCCs provided by the partnerships of which you are a member.

[6] If the tax year is shorter than 12 months, prorate the Yukon mining business carbon price rebate or the Yukon general business carbon price rebate by the number of days in the tax year divided by 365.

[7] Use the mining business rebate factor for the Yukon financial year in which the tax year ends.

The mining business rebate factor is equal to:

- $5.27 for each $1,000 of eligible Yukon mining UCC if your tax year ends between January 1, 2023 and March 31, 2023 (enter 0.00527)
- $21.08 for each $1,000 of eligible Yukon mining UCC if your tax year ends after March 31, 2023 (enter 0.02108)

[8] The following classes are prescribed for the purposes of the definition **eligible Yukon asset**:

(a) Classes 1 and 3

(b) Classes 10, 10.1, 13, 16, 22, 28, 29, 38, 39, 40, 43 and 53

(c) Classes 43.1, 43.2, 54, 55 and 56

The classes prescribed for the purposes of the definition **eligible Yukon asset** are subject to change.

Where the list of classes provided here differs from that provided in the Carbon Price Rebate General Regulation, the latter takes precedence.

[9] The inclusion rates for prescribed classes of eligible Yukon assets are:

(a) Classes 1 and 3: 50%

(b) Classes 10, 10.1, 13, 16, 22, 28, 29, 38, 39, 40, 43 and 53: 250%

(c) Classes 43.1, 43.2, 54, 55 and 56: 500%

[10] If you are a member of a partnership that is an eligible Yukon business partnership, the eligible Yukon UCC at the end of the year from the partnership is equal to your specified proportion of the eligible Yukon UCC to the partnership at the end of the partnership's fiscal period.

Enter the total of all eligible Yukon UCCs provided by the partnerships of which you are a member.

[11] If you are an eligible Yukon mining business taxpayer, enter amount D. Otherwise, enter "0".

[12] Use the general business rebate factor for the Yukon financial year in which the tax year ends.

The general business rebate factor is equal to:

- $39.62 for each $1,000 of eligible Yukon UCC if your tax year ends before April 1, 2023 (enter 0.03962 at line 500)
- $21.89 for each $1,000 of eligible Yukon UCC if your tax year ends after March 31, 2023 (enter 0.02189 at line 500)

YUKON UTILITIES BOARD

YUKON ELECTRIC COMPANY LIMITED 2016-2017 GENERAL RATE APPLICATION

P R O C E E D I N G S

Volume 3

November 3, 2016

Whitehorse, Yukon

Proceedings taken at the Coast High Country Inn, at 4051-4th Avenue, Whitehorse, Yukon.

Volume 3

November 3, 2016

Mr. R. Laking	Chair
Mr. A. Fortin	Board Member
Ms. B. King	Board Member
Ms. M. Hannam	Board Member
Mr. P. Fitzgerald	Board Member
Ms. A. Sabo	Board Counsel
Ms. L. Mullen	Board Staff
Mr. B. Clarke	Board Staff
Mr. D. Ward	Board Staff
Ms. D. Lemke	Board Staff
Mr. B. Williams	For the Yukon Electric Company Limited
Mr. J. Epp	For the Yukon Energy Corporation
Mr. T. Marriott	For the City of Whitehorse
Mr. R. Rondeau	For the Utilities Consumers' Group
Ms. A. Middler	For the Yukon Conservation Society
Mr. J. Maissan	In his own stead
Ms. D. Harmata, CSR(A) Ms. A. Jones, CSR()	Official Court Reporters

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(PROCEEDINGS COMMENCED AT 8:34 A.M.)

THE CHAIR: Good morning, everyone. Thank you for being here.

We still have the YECL panel up. And I just remind everyone about cellphones again. I did mine.

And do we have any housekeeping matters this morning?

MR. WILLIAMS: Yes, sir.

T. MARTINO, J. GRATTAN, D. TENNEY, J. MASSIE

(For ATCO Electric Yukon General Panel), previously sworn

UNDERTAKING RESPONSES:

MR. WILLIAMS: We have three undertakings. Maybe I'll start the morning by saying I'm sure I'm not the only one thankful to be in the Pacific time zone this morning given last night's baseball game. 08:34

The first undertaking, sir, is Volume 2 of the transcript, page 226, lines 18 to 20. And that is an undertaking given by Mr. Martino to Mr. Rondeau.

THE CHAIR: So I think that will be Exhibit B-20; is that correct? Yes? B-20.

EXHIBIT B-20 - RESPONSE TO UNDERTAKING PROVIDED BY MR. MARTINO TO MR. RONDEAU IN VOLUME 2, PAGE 226, LINES 18 TO 20 08:35

THE CHAIR: All right.

MR. WILLIAMS: Thank you, sir.

The next is Transcript Volume 2, page 242, lines 6

to 11. And that is an undertaking given by Mr. Tenney to Mr. Rondeau.

THE CHAIR: That will be Exhibit B-21.

MR. WILLIAMS: Thank you.

EXHIBIT B-21 - RESPONSE TO UNDERTAKING PROVIDED BY MR. TENNEY TO MR. RONDEAU, VOLUME 2, PAGE 242, LINES 6 TO 11.

MR. WILLIAMS: And the final one I have for you this morning, which would be Number 9 on your list. So we're skipping Number 8 this morning. And that is Transcript Volume 2, page 385, lines 11 to 16. And that is an undertaking given by Mr. Tenney to Ms. Sabo, and I believe that would be 22. 08:36

THE CHAIR: Yes. That will be B-22.

EXHIBIT B-22 - RESPONSE TO UNDERTAKING PROVIDED BY MR. TENNEY TO MS. SABO, VOLUME 2, PAGE 385, LINES 11 TO 16

THE CHAIR: So what do we have left at this point? 08:36

MR. WILLIAMS: At this point, sir, I believe we have -- we're cleared off the board for Day 1. We have Number 8 on your list from yesterday outstanding.

THE CHAIR: All right.

MR. WILLIAMS: And I'm not sure that we're going to be able to get that to you today. So we may need to get that in after the proceeding closes for the day today.

And I also understand that one of the subject to checks provided yesterday will need a follow-up. So we'll have two follow-ups arising from yesterday that are unlikely to be delivered before the close of proceedings today.

THE CHAIR: Thank you. 08:37

So are we ready to proceed now?

Yes. All right. Ms. Sabo.

MS. SABO: Thank you, Mr. Chairman.

MS. SABO QUESTIONS THE PANEL:

Q. Yesterday we left off, panel, on FTEs, and I'd like to take you this morning to Exhibit B-9, which is the responses to the Board, 28(a) and 28 (b), which are on pdf page 268, hard copy page 101.

And these responses are in respect to ATCO Electric staff reductions as a result of the 08:38 restructuring. And we understand that ATCO Electric Yukon doesn't know the number of positions reduced.

But are you aware whether ATCO Electric Limited undertook a general reduction to all departments, or were there department-specific reductions?

A. MR. GRATTAN: So I can respond to that. So to answer your question, there were reductions within ATCO Electric across all aspects of the organization. And subsequent to the response to this interrogatory, I can advise that ATCO Electric -- I was able to determine that ATCO Electric decreased its labour complement by approximately 600 people last year.

Q. Okay. And, Mr. Grattan, I don't think we have a lot of information available on this record on the restructuring. Can you give us an idea why the ATCO Group undertook the reorganization? And I understand it's partly due to the economic downturn, but maybe you can help us out and give us some context. 08:39

A. MR. GRATTAN: So I would rephrase that slightly -- actually, significantly --

Q. Okay.

A. MR. GRATTAN: -- I would say in large part due to the economic downturn in Alberta. Alberta, as well as ATCO Electric, in the years leading up to 2015, was seeing tremendous growth, and that all came to an end as 2014 rolled around, and then into 2015 and continuing through to today. 08:40

So that is, by far, the largest driver as to what ATCO Electric is dealing with in Alberta.

Q. Okay. And similarly, what impact, if any, did the

ATCO Group reorganization have on ATCO Electric Yukon's workforce complement?

A. MR. TENNEY: It didn't have any impact on our -- ATCO Electric Yukon specifically.

Q. And why is that the case, Mr. Tenney?

A. MR. TENNEY: Well, we're obviously in a -- a standalone utility. We are in a separate geographical location. We also were instructed to review our workforce as it related to our -- what we needed to do to accomplish -- to continue to provide safe, reliable. 08:41
So we did also have a look at our staffing, and we didn't deem that we needed to change anything on a go-forward basis.

Q. Okay. So just to make sure I understand, is it fair to say that the ATCO Group reorganization was company-wide but specifically for ATCO Electric Yukon, the top-down direction was just to review it due to the specific needs of ATCO Electric Yukon?

A. MR. TENNEY: Right. I think that's what, I mean, ATCO Group, the way I understand it, was looking 08:42
at all aspects, and every group took a look at what their -- what it looked like in the coming years. And we were no different. We were instructed to do the same, as was in the Northwest Territories.

Q. Okay. Thank you. And now moving to IR 27(a) of that

same exhibit. In the response to Part (a), it states, in part, on pdf page 267: (as read)

"No across-the-board wage freezes were imposed in the 2014-'16 period. Employees received increases in 2014, and some employees received wage increases in '15 and '16."

And did all employees in 2014 receive wage increases?

A. MR. TENNEY: I don't have that at the tip of my fingers, but I would suggest that probably all employees received wage increases in 2014. 08:43

Q. Okay.

A. MR. TENNEY: It would have been subject to satisfactory performance reviews, but absent that, I would think everybody did in 2014.

Q. And for 2015 and 2016, for those staff that did not receive wage increases, were they all out-of-scope positions, or were some of those in-scope positions?

A. MR. TENNEY: In 2014 and 2015, as well as 2016, we -- the folks that are in-scope were covered by a collective bargaining, so they for sure received wage increases. 08:43

So in the updated response, where we talked about 15 percent did not receive wage increases in 2015, and 17 percent in 2017 that did not receive them would have

all been out-of-scope.

Q. Okay. And just for the record, that's --

A. MR. GRATTAN: Sorry.

Q. Sorry?

A. MR. TENNEY: Sorry, yeah, I said 2017. I was talking about '15 and '16. So in 2015, 15 percent did not receive wage increases. And in 2016, 17 percent did not.

Q. Thank you. Mr. Tenney, I was going to do that myself. Yeah, the exhibit that, where you're talking about the update, is the September 9th, 2016, response to that same IR 27(a), and that's Exhibit B-11. So thank you for that correction. 08:44

I would like to talk a little bit about labour inflation, and I'm going to take you to Board Order 2014-06, Appendix A, and page 24. And while you're finding that, there's a paragraph that reads: (as read)

"In the application, YECL submitted the labour inflation rate of 3.5 percent for 2013, '14, and '15, for both in- and out-of-scope labour. YECL stated that the 2013 and 2014 escalators were based on its collective agreement that expires on December 31st, 2014, and the 2015 08:45

escalations are based on its forecast of the increase required."

And then in the findings sections, the views of Board, it states at 5.3.2: (as read)

"The Board recognizes that YECL's labour inflation forecasts have been reviewed in this proceeding, and in light of the awards in other jurisdictions is confident that the labour inflation forecasts provided are reasonable for the test period." 08:46

And then they approved those labour inflation increases.

So given that ATCO Electric Yukon was awarded an inflationary increase for labour in 2015 and given that wages for out-of-scope labour did not increase as to the level forecasted in 2015, how have those considerations been factored into the proposed labour inflation increases for out-of-scope employees in '16 and '17?

A. MR. TENNEY: Sure. I think any time you prepare a forecast, you're using the best information you have at the time you prepare the forecast. And obviously as you move throughout that test period, certain line items are going to be greater than -- actuals are going to come in greater than forecast, and some are going to come in less than forecast. That's 08:47

just the nature of how it works.

So on a go-forward basis when we prepared our forecast, we were using the best information we had at the time, and that was what we came to on labour escalations.

And I think if we look back historically -- and Mr. Massie can probably jump in and help me with the exact percentages -- but I think overall when you look at what the Board approved in the 2013 to 2015 time period for O&M, I think our actual numbers came in 08:47
fairly close to those forecasts, and yet when you go to any particular line item, you can find where we were not on on forecast. But, in total, we were pretty close.

Q. And I think that was mentioned yesterday as well. Mr. Massie, anything to add?

A. MR. MASSIE: Yeah, I would say Mr. Tenney is referring to our overall O&M forecast. And, again, we -- as stated yesterday in our application page 52 -- we were within 1.1 percent of our $35 million forecast. 08:48

And, really, on those line items that we look at in there, there was, again, higher and lower values between the actuals and what was forecasted, but overall, the bottom number, I guess, is what we were discussing there of being fairly accurate.

Q. Okay. And, Mr. Massie, are you able to confirm the actual inflationary increases for in-scope employees from -- for each of the years from 2013 to '15? Do you have those numbers?

A. MR. TENNEY: Your question was for in-scope employees; correct?

Q. That's correct.

A. MR. MASSIE: I don't have those at my fingertips. They are subject to the collective agreement. I know our collect -- we had collective agreements for each of those years in place, including 2016 is the expiry of the current collective agreement.

Apparently, my colleague does have it. So...

So for '13, '14, and '15 for the three years for in-scope in our collective agreement were 3.5 percent increases in labour for each one of those years.

Q. Okay. Thank you. In responses to several Board IRs between 40 -- Numbers 40 and 45, ATCO Electric Yukon explained that parts of the reason for the variances in certain accounts, for example, production accounts, related to inflation and cost-of-living adjustment.

Can you explain the relationship between the cost-of-living adjustment and the increases in the inflation that affects those accounts?

It's between 40 and 45 of the IRs, Mr. Grattan.

08:49

08:50

A. MR. MASSIE: Sorry. I think we've got this figured out. So looking at the -- and we'll look at specifically YUB-40 in the tables there, because they're very similar for -- as you say, for 40 to 45.

Q. Thank you.

A. MR. MASSIE: The inflation number -- in that number, we do have our labour inflation for year to year. There will be general inflation. So the CPI on materials, and if we need any contractor help in those -- in those accounts, that will be caught in there. So materials, labour. 08:53

Anything else? Are caught in that inflation number.

In the COLA, I believe Mr. Grattan will speak to.

A. MR. GRATTAN: So all that -- that COLA relates to is the pension, the change in pension funding requirements between 2015 and 2016.

And as part of this application, ATCO Electric Yukon has requested that 100 percent of COLA be included in the forecast, subject to it being a placeholder to ultimately be determined by the Alberta Utilities Commission tied to a current pension application that is before the regulator down there. 08:53

So if you harken back to the last general rate application and ATCO Electric Yukon being before this

Board, there was a determination by this Board that COLA should be limited to 50 percent, included in revenue requirement, cost-of-living allowance.

So if is -- if the funding required by the actuarial parties said that ATCO Electric Yukon needed to fund pension dollar, and that dollar related to COLA, this Board made a determination that only 50 cents of that dollar should be included in the revenue requirement.

Q. Okay. Thank you, Mr. Grattan, and, Mr. Massie. 08:55

I think we were just a little confused by the language on there, whether the inflationary increase in COLA were having an impact -- a corresponding impact to each other. And I think I'm hearing that, no, they're separate components there.

A. MR. GRATTAN: Yes.

Q. Okay. Thank you.

I would like to take you to our final aid to cross, Aid to Cross 7, which is Schedule 5.1, O&M maintenance expenses. 08:55

Okay. And the aid to cross simply adds in the columns and the variances between the actual and the approved for the three years, '13, '14, and '15.

And I should note for the panel, Board staff has calculated the variance percentages from those variance

column numbers that are highlighted in grey on those -- those tables are blue if you're -- you've got an electronic copy. I'll be referring to variance percentages in these questions.

And I would appreciate -- I know the panel's going to have to take those subject to check. So if any of them are wrong, please let us know.

At a high level -- or maybe I should ask first: Is there any corrections to the variance amounts in this table? Have you looked at that, panel? 08:57

A. MR. GRATTAN: We haven't been advised by our financial folks that there's any concerns on it yet, but subject to check, it should be okay.

Q. Okay. Thank you. And I just would like some responses at a high level. I don't want to get too detailed in the numbers. We're looking at trends. But for the production section, starting at line 1, the largest variances pertain to hydrogeneration, which is Account 62600, and diesel maintenance, which is Account 84600 at lines 2 and 6 respectively. The 08:58 average variance over the three years in our calculation is about 36 percent for the hydrogeneration and about 15 percent favourable for the account for diesel maintenance.

And for these accounts there appears to be a trend

of underspending relative to the approved amount for each of these three years. So we would just like a high-level explanation on why that's the case.

A. MR. MASSIE: Okay. I'll -- I'll give the high-level overview of it.

So as we looked at -- the aid to cross, noticed the variances that you noted. Some of the things that we looked at that would cause that came to light. So we're really seeing a decrease -- one of the items is a decrease in labour, internal labour, as our folks really got focussed, again, on that intensive generation capital program that we had. 08:59

We -- quite frankly, we underestimated how much time and effort that they would need to be put into that capital program. So that offset part of those operating accounts.

With -- also in line with that generation capital program, we realized that -- and if we look at the test years of '13, '14, and '15, and I believe we put in seven new diesel generators, one new hydro unit. So that was another miss that I think we had with our forecasts, was understanding the -- how the new units would have less maintenance needed during that test period. 08:59

Brand new units obviously going into service would

be requiring less maintenance in that short term. And if I could turn you to UCG-44, Attachment 1, and you might be able to have a look at that and see it more clearly.

Q. I'm there, sir.

A. MR. MASSIE: Okay. So in this response, we were asked for our capital expenditures and O&M expenditures and -- in diesel, just diesel -- for this ten-year span. And if we just focus at that top line at capital expenditures and we look at, 09:01 specifically at 2012. So you'll notice the capital expenditures for those six years prior were significantly less than our program that started in 2012, '13, and '14, and '15. So the capital expenditures, as our program ramped up, and we had quite a bit of work to do, as seen there in those numbers.

And then you'll notice in -- a similar trend with O&M expenditures that were fairly flat for '11 and '12, and then that dip happened in '13, '14, and '15, 09:01 compared to those earlier years.

And, really, I think that just illustrates what I was explaining there, that our program, our capital program, was fairly intensive. So it off-loaded both our labour, as well as the maintenance on the actual

units. And I think that's one thing that we -- we missed in that forecast, just being that it's been some time since we had as intensive a capital program in generation.

But that being said, if we go back to the aid to cross and your hydrogeneration specifically on line 2, you know, we've realized that, and we've adjusted our forecast. You'll notice from the approved level in '15, a significant drop to '16 and moving forward.

So the forecast was -- there was a couple items missed, for sure, in the last go-around. We feel that we've adjusted for that going forward, though. 09:02

Q. Okay. And, Mr. Massie, looking at line 5, which is hydro maintenance costs, would that same rationale, too, apply -- those same reasons you just gave me apply to the -- why there's an increase of 25 percent from 2016 to 2017 forecasts?

MR. WILLIAMS: Sorry, if I could just -- before Mr. Massie answers that, I just want to be clear on the record that the aid to cross is the original Schedule 5.1, and there's an updated Schedule 5.1. 09:03

MS. SABO: So, yeah, the only addition to the aid to questioning is the grey portions.

MR. WILLIAMS: No, and that's why while we were just talking the actuals --

MS. SABO: Yeah.
MR. WILLIAMS: I don't see any problem, but if we're going to start talking about '16, '17, I'm fine to continue with the aid to cross, obviously, but I just want to be clear on the record that there is an updated Schedule 5.1.
MS. SABO: Yes. And certainly, yeah, if we need to refer to that updated schedule, we will. Thank you for that addition, Mr. Williams.
MR. WILLIAMS: Sorry for interrupting. 09:04
MS. SABO: No, that's -- thank you.
A. MR. MASSIE: So line 5 hydro maintenance, the increase in '17 will reflect the full year of the mechanical technologist being in place. That's in part of that, the labour increase for that position as that position is split between the hydro and diesel accounts.
Q. Okay.
A. MR. MASSIE: Also, in '17, we've factored in that we have an updated dam safety review that needs to be done for our Fish Lake project. So those are a requirement of our water license. And we have -- they get updated every year. So we have one in place, and every year we have a subject matter expert head out there, complete that review. 09:05

In 2017, it's -- we're having a third party subject matter expert basically to ensure that what he's being doing for us for the last 10 years is accurate. So, next year, the new person or contractor that we put in place to do that review will have to start with a blank piece of paper, whereas, when we get those done on a yearly basis, they're able -- our fellow is able to look at his notes from the year before at different changes for the Fish Lake system to it. So it's not as intensive as it will be in '17. 09:06

Q. Okay. Now turning to the distribution section of that table, starting at line 8. Account 8700 for supervision appears to have a consistent negative variance; that is, actuals exceed approved levels. So can you explain that, sir, what's going on there?

A. MR. MASSIE: That the actuals year over year are more than the approved levels?

Q. Yes.

A. MR. MASSIE: Is that the question?

Okay. I really think that would be a factor of being a full complement. The -- that account, 87000, the labour charges that get charged in there are preset. So there's no -- our PLTs, our technicians that work in the distribution that have labour accounts in there, they do time sheets on a regular basis to 09:06

whatever account that they're working on at the time.

The supervisors and management that have preset labour, they'll use those -- that account there in distribution to put it -- to put their labour too.

So it really should be -- the only fluctuations that would be in there is if we have fluctuations in our complement as it -- again, they're preset labour costs to those -- to that account.

Q. Okay. And taking that the next step, can you explain why supervision is expected to increase in 2016 over 2015 actual levels? 09:08

A. MR. MASSIE: I think that increase -- I see that increase is at 2.5 percent. That would be the increase from '15 to '16.

Q. I don't have the updated schedule in front of me, Mr. Massie. So, yeah, just -- I'm just generally...

A. MR. MASSIE: Okay. Yeah. That's what -- I have the column here beside the '15 to '16 increase. Yes. At 2.5 percent. So at 2.5 percent, I would assume that's the -- our general inflation numbers that we have in our -- that we've applied for. 09:08

Yeah. Without digging into it further, Ms. Sabo, that would be what I would think is in there for the 2.5 percent.

Q. Okay. Thank you.

At line 10 for Account 87100 for brushing costs, 2014 brushing costs were underspent, and your application stated that this is due to availability of resources.

So can you give me some detail on the issue with brushing in 2014?

A. MR. MASSIE: Sure. In our brushing account, we have, actually, fairly small labour dollars. We have just a person that will coordinate our brushing program. The vast majority of the costs are 09:09
contractors, brushing contractors that we -- we employ.

So in 2014, there was an issue in getting the brushing contractors focussed on our program. There's other programs in the territory by -- the Yukon Government has their highway brushing program. Yukon Energy has a brushing program. There's a number of other competing companies out there that employ these individuals. And if they're locked down on those projects, sometimes it's very difficult to get them back in to focus on our program. 09:10

So I believe that's what our description was about in the 5.2 schedule, was that the contractors -- there was a tough time getting -- getting them that year.

Q. And that's what happened in '14; yes?

A. MR. MASSIE: '14.

Q. Moving to line 11 for Account 87200, vehicle depreciation, can you explain why there's been a positive variance in past years, '13 to '15?

A. MR. GRATTAN: So all that is, is the -- our vehicles are -- have a charge per hour. So when an employee uses a vehicle for O&M purposes or capital purposes, it goes into a vehicle pool. And whether that includes -- or that includes insurance and gas and maintenance and that the depreciation of the vehicle.

So depending on whether that particular vehicle was used for more or less capital-related items, we have to back out more or less out of the O&M to account for that depreciation that's being charged into O&M. 09:11

Q. Thank you, Mr. Grattan.

The streetlight maintenance at line 17, which is Account 87800, is expected to increase in 2016 over actual levels. And we would just like to know the drivers for that increase.

A. MR. MASSIE: Okay. Just having a quick look at it, the line down there, I would say, it isn't so much the increase in '16 as it was a decrease in '15. If we look at our actuals from '13 and '14 of 238 and 252, more indicative of what we would expect out of our streetlight maintenance program. 09:12

In '15, it was less than any one of those years,

of '13, '14, and '16. And I would say that, quite honestly, the streetlight maintenance account is -- even though we are proactive and we do patrol and we find out what streetlights are off and repair them, get them running again, it can be very reactive. If there's less streetlights that burn out or to fix, there's less work to do.

So I would say in '15 that that -- that would be the only cause for that drop in '15. So the '16 number I would say is more indicative of what we've looked at or had for streetlight repairs in the past. 09:13

Q. For Account 70220, which is at line 26, that's the general public information account, the forecast increase from 2016 is -- we calculated it at 15 percent. It might not be that percentage in the updated table.

Can you give an explanation on why the increase between 2016 and '17 forecast?

A. **MR. MASSIE: What I think we looked at for that general public information really was the -- there's a focus -- or it's more of a demand by customers of better information for the projects that we do. So one of the learnings we had was just this year in our Selkirk Street substation -- in the past we've gone -- we had a project; we had a business need. We went out** 09:14

and did the project. There really is more of a concern or a want from the public to understand what we're doing a bit more.

So for our Selkirk Street substation this year, we went and met with the Riverdale Community Association, heard any concerns they had. We had a town hall meeting. We did -- out of that, we did a program where we sent out messaging to all those customers of what the project was, what we were doing, why we were clearing out a section of the forest in the back of Riverdale to put a new substation in there. 09:16

So we did all this messaging specifically for the community association. We had message boards near the site to ensure that everybody knew why it was going there. We had meetings where the local high school and elementary school that were nearby, just so they understood that it was a construction site.

So just looking at the amount of effort that we put in before we even started that project really made us realize that this public messaging is going to grow a bit. There is that want and that need from the general public to understand what we're doing, as opposed to our past business practices of, you know, we have a project to do, we're just going to go do it. 09:16

Q. Okay. For the customer accounting group of accounts

starting at line 28, using these numbers for those accounts, the Board noticed that often the variance percentages is 4 percent or greater. And, Mr. Grattan, I'm just wondering if you can give me a sense on any important changes within those accounts that would explain why some of the variances are higher than inflation -- or Mr. Massie.

A. MR. GRATTAN: Yeah, I'll be able to speak a little bit to Account 713, which is the customer billing and accounting line, but that one -- that one's -- that was what I was mentioning yesterday where we had a significant decrease in what has actually been incurred in customer billing and accounting. So that's ATCO 71300. 09:17

Q. And that's at line 32?

A. MR. GRATTAN: Line 32, exactly. And as I mentioned yesterday, that account went from an actual of $774,000 last year down to -- sorry, two years ago, 2014, down to an actual of 600,000 in 2015. And that was -- that decrease is due in large part to ATCO Electric Yukon and ATCO as a whole changing customer care and billing service providers -- or, sorry, no longer going with an affiliate ATCO ITBS and going internally well with Wipro. 09:18

So that decrease -- and that decrease also

includes the additional FTE that we were talking about yesterday.

Q. Okay.

A. MR. GRATTAN: So on a net basis, there still is a decrease, even though we've added to the complement of one FTE.

Q. Okay. And, Mr. Massie, can you identify any others there that require specific mention on variances?

A. MR. MASSIE: I can -- I'll walk through the accounts, and I'm just trying to highlight the ones that have the variances. 09:19

So, again, the 7-1, the first item there, line 29, supervision, that is a preset number based out of the supervisory folks that work in that account. So they had preset labour levels, very similar to the -- what I spoke to earlier.

The next line item, customer applications and services, that -- the costs in there are, when customers phone in, they need us to go out and -- they're moving in to an apartment, moving out. We are going to read the meter, disconnect, reconnect those services. So it's very reactive. So it's based on our historical numbers. The increase into '16 I would say is based on our past historicals of what we think is going to happen for customer services. So I would 09:20

guess it would be, as customers are added, as our customer base grows, there should be more people that we'll have to deal with in that account.

Meter reading is pretty straightforward. These are the costs for our fellows in the field that go out to read the meters every day. This is a cost for each one of our communities throughout the Yukon. So...

Again, the increase to '16 from '15 -- I'm just trying to get my head around why we'd -- why there would be the increase from the actuals in '15. Labour inflation in COLA. So, really, there's no -- other than the incremental growth of customers and having a few more meters to read, there would be a few more meters to read, as well as in there should be labour inflation in those COLA percentages that Mr. Grattan spoke to earlier. 09:21

Q. Okay.

A. MR. GRATTAN: And just to make sure that everybody's on the same page with regards to COLA, as part of our update that we filed in October, we've reflected the latest information from our actuary that has resulted in a reduction in the pension funding requirements for 2016. So as Mr. Tenney mentioned earlier, all of these numbers are going to be slightly lower in 2016 if we were to go through this exact same 09:22

exercise after reflecting reductions in COLA.

Q. Understood, Mr. Grattan. Thank you for that addition.

A. MR. MASSIE: Okay. And revenue collections I would say were beneath the 174 in '16 is under the three-year average. So, again, we work of historical averages in that it's a pretty straightforward account and revenue collections of what we do there.

Q. You must have been watching the baseball game last night, Mr. Massie.

A. MR. MASSIE: I may have. I'm a Cubs fan, so I'm pretty -- yeah, I was okay with the outcome. 09:23

All right. And I see the line item 34, 71,500 is -- is an average of those three years. The 130 is average of those three years, so that's what we've looked at for that as well as, I believe, for that last line item.

Again, those are -- they're very reactive accounts, the collection of delinquent accounts and uncollectible accounts. So we base them on our recent historicals. 09:24

Q. Okay. Thank you, Mr. Massie.

MS. SABO: Chairman Laking, if we could mark exhibit -- or the Aid to Questioning Number 7 with an exhibit number, that would be appreciated.

THE CHAIR: Yes. I think that would be

Exhibit A-21.

EXHIBIT A-21 - AID TO QUESTIONING

NUMBER 7

Q. MS. SABO: I would like to move to some questions on depreciation and income tax. And I would like to take you, Mr. Grattan, to Schedule 7.4 of your GRA schedules at Exhibit BB-1(a). And, specifically, Schedule 7.4 at line 50.

And at line 50, the amortization of reserve differences amount is $402,000 for 2016 and '17. 09:25

Do you see that, sir?

A. MR. GRATTAN: I do.

Q. And is that amount the same as the amount that you used in the 2013 to 2015 GRA?

A. MR. GRATTAN: When you say "used in the 2013 to '15 GRA," do you mean what was approved?

Q. Yes. What you forecasted to be approved, yes.

A. MR. GRATTAN: I'm going to say, yes, because that's what -- it's a consistent number throughout the '13 through '17 period of 402. So, yes. 09:25

Q. Thank you.

And keep that schedule open, but I'm going to move to Board Order 2014-06, Appendix A, page 44. And you might not need to pull it up.

In that section, the Board denied the collection

of future removal and site restoration costs in its depreciation rates; yes?

A. MR. GRATTAN: Correct.

Q. Okay. Can you confirm if FRSR is essentially the same as a negative -- as negative net salvage, which is represented by the percentage net salvage amounts shown in Schedule 7.4?

A. MR. GRATTAN: At a global basis, I would say the future reserve for site restoration is collecting money today from -- to pay for future site restoration costs. So I think I can agree with your characterization. 09:27

Q. Okay. Thank you.

So do the FRSR negative salvage percentages form a component of the depreciation rate or the calculation of the amortization reserve of differences amounts shown in Schedule 7.4?

A. MR. GRATTAN: Actually, you know what, I'm going to correct my statement on that. So I apologize.

Q. Okay.

A. MR. GRATTAN: So the amortization of differences is not relating to a collection of amounts that are going to be used for future site restoration. It's basically, as I understand it, a -- the difference between what depreciations were previously versus what the latest depreciation study that was approved in 09:27

2013-'15 GRA and amortizing those differences on a go-forward basis. So it is separate and distinct from collecting dollars today to be used tomorrow for future reserve site restoration purposes.

Q. Okay.

A. MR. GRATTAN: I apologize.

Q. No problem. So can you explain how that -- that's reflected in the component of the depreciation rates shown in Schedule 7.4?

A. MR. GRATTAN: Can I show? I'm not sure I can show you much more than what is there -- 09:29

Q. Okay.

A. MR. GRATTAN: -- other than to say that we have simply continued what the Board approved as part of the 2013-'15 General Rate Application for amortization of differences, that $402,000 going forward into this test period. And that would be consistent with past practice when we don't have a depreciation study before the Board.

Q. One moment. Okay. And now I have a question on approved depreciation rates and depreciation expense. So if I could take you to Schedule 7.2. 09:30

A. MR. GRATTAN: I am there.

Q. Great. At line 46, a depreciation or amortization rate of 20 percent is being used for Account 49300,

Demand Side Management; yes?

A. MR. GRATTAN: Yes, five years.

Q. And can you confirm that the 20 percent depreciation rate shown is the current Board-approved depreciation rate? Because when we pulled up the schedules from the last GRA, it seemed to be that 10 percent was in that account, Mr. Grattan. I know I'm kind of putting you on the spot, but can you help me out with that?

A. MR. GRATTAN: So, actually, maybe I need to go back to the Board -- the Board Order 2014- -- 09:31

Q. 2014- --

A. MR. GRATTAN: -- 06. This may just take a minute.

Q. Take your time, sir.

And I think you might want to look at pdf page 95. That may or may not have the amount, or you might have to go to the schedule.

A. MR. GRATTAN: Okay. So I haven't found it. So I think the concern appears to be whether it should be amortized at 10 percent as opposed to 20 percent? 09:33

Q. Yes. Yes, Mr. Grattan.

A. MR. GRATTAN: Is that the concern?

So if I could undertake -- rather than eating up time here, if I could undertake to confirm why we've -- why we've got it at 20 percent for five years, would

that be helpful?

Q. Yes. Thank you, Mr. Grattan.

If you could undertake to check that and get back to us either at a break or in writing.

A. MR. GRATTAN: Most definitely.

Q. Thank you.

UNDERTAKING - CONFIRM THAT THE 20 PERCENT DEPRECIATION RATE SHOWN IN BOARD ORDER 2014-06 IS THE CURRENT BOARD-APPROVED DEPRECIATION RATE

09:31

Q. MS. SABO: Thank you. And in Account 49300 for Demand Site Management on Schedule 7.2, we would like more detail on the underlying calculation of the recovery of the DSM program through depreciation. In our review, the information, there were capital additions in 2016 of 534,000 that do not appear to be attracting depreciation or amortization expense in any amount. So the depreciation expense calculation does not appear to follow other accounts. And we were just wondering if you knew why that was the case.

09:34

A. MR. GRATTAN: So I think if I'm -- as I look at the schedule, as we've done it, we have -- as I understand, we have proposed to add the $534,000 of DSM costs incurred in the years -- I'm going to say '14, '15, and '16. Just one moment. Let me just

double-check that, please.

Q. Take your time.

A. MR. GRATTAN: Yes. So I think I've got it right. Include the DSM incurred in 2 -- DSM costs incurred in 2014, '15, and '16, a total of 535 that was previously approved by the Board. Add it to rate base in 2000 and -- capital rate base in 2016. And we, per these schedules, begin to amortize that on a five-year basis, beginning in 2017. That's what -- the way the schedules are shown. 09:36

Q. Okay.

A. MR. GRATTAN: And if I -- just to -- there is a -- as you've already noted, there is a previous amount in property, plant, and equipment that, as you've noted, we've been amortizing over five years prior to the transfer of the 534 in 2016.

Q. Thank you. So if you're capitalizing it in 2016, why isn't it attracting depreciation?

A. MR. GRATTAN: It's a good question, and I don't have a great answer for you. If it was ultimately 09:37 **determined that that was the reasonable way to go, I wouldn't have a problem with that.**

Q. Okay. And is there -- there's -- is there a specific reason why it's reflected as it is? Can you...

A. MR. GRATTAN: I do not have a good answer for

you on that.

Q. Okay.

A. MR. GRATTAN: To be helpful, I can certainly undertake with my financial folks if you would like a better answer. I've got no problem taking an undertaking on that.

Q. Yeah, that would be helpful, Mr. Grattan. Maybe you could provide me an explanation on why it's been reflected the way it has and --

A. MR. GRATTAN: Sure. 09:38

Q. -- alternately, if it should be attracting depreciation.

A. MR. GRATTAN: I will undertake to find out why we're starting to amortize that 534,000 in 2017 as opposed to 2016.

Q. Thank you.

UNDERTAKING - TO ADVISE AS TO WHY THE 534,000 IS STARTING TO BE AMORTIZED IN 2017 AS OPPOSED TO 2016

Q. MS. SABO: Similarly, we were looking at 09:38 Accounts 423 and 425 again in Schedule 7.2. And we're trying to determine whether there's been a mixup between these accounts. So if you look at Schedule 7.2, I'm looking at lines 3 and 4 which deal with those accounts. And I would like you to compare

the plant balances for those accounts between those used in Schedule 7.2 -- so the ones that are there -- with the ones in the technical update that were provided in response to the City of Whitehorse 19, which is at Exhibit BB-1(a), pdf page 167. So, again, that's 19 is the IR number, and the pdf page is 167.

A. MR. GRATTAN: One moment, please.

Q. I'm sorry, the responses to the City of Whitehorse are at Exhibit B-4.

A. MR. GRATTAN: And, sorry, what page of the Attachment 1 was the reference that you had? 09:39

Q. 167 of 346.

A. MR. GRATTAN: I don't have that. I've got the technical update detailed on page 1. I've got 42 pages --

Q. Oh, sorry, 42 of 42.

A. MR. GRATTAN: Okay. Thank you.

Q. So I'll give you the context here, Mr. Grattan, as you're looking at that. So on a mid-year basis for Account 423 for hydro reservoirs, dams and waterways, 09:40 Schedule 7.2 indicates an opening PP&E balance of 2.2 million and a 2016 capital addition of

.735 million, which translates roughly to a mid-year balance of 2.6 million. Is that about right?

A. MR. GRATTAN: Yes.

Q. Okay. And similarly, for Account 425, hydro generators, it indicates the 2016 opening PP&E balance of 5.2 million and a 2016 capital addition of 1.6 million, which translates roughly to a mid-year balance of $6 million. Yes?

A. MR. GRATTAN: Yeah, I can agree with you.

Q. Okay. Now, turning to the technical update at page 42 of that IR response, in comparing these totals to the mid-year balances for the same two accounts, they do not result in equivalent mid-year balances. For example, Account 423 is 5.1 million rather the 2.6 million is Schedule 7.2. So that's why we're wondering if there's maybe a reversal in those accounts or there's been an error. 09:41

A. MR. GRATTAN: So all good questions, and I think I'm going to need to undertake to --

Q. Okay. 09:41

A. MR. GRATTAN: -- make sure that we've either got a correction or whether it's right.

Q. Okay. So to confirm the undertaking, Mr. Grattan, you'll undertake to provide us with an explanation or a correction explaining Account 423 and 425 and whether

there's been a reversal or error in those two accounts.

A. MR. GRATTAN: Yes. I will undertake to do that.

Q. Thank you.

UNDERTAKING - TO PROVIDE AN EXPLANATION OR A CORRECTION EXPLAINING ACCOUNT 423 AND 425 AND WHETHER THERE'S BEEN A REVERSAL OR ERROR IN THOSE TWO ACCOUNTS

Q. MS. SABO: I would like to move to income tax. And can you turn up your response to the Board IRs, 49(b). And that's Exhibit B-9. And the pdf page I've got 333 of 414. So 333 is the pdf. 09:42

A. MR. GRATTAN: I am there.

Q. Okay. Thank you.

Since the time of the IR response on July 11th, 2016, and specifically Part (b), which indicated that ATCO Electric Yukon was not aware of any proposed changes to income tax rates, have you received any updated information with respect to any enacted or announcements that would affect federal or territorial income tax rates? 09:43

A. MR. GRATTAN: Yes. And it's -- I don't want to give the liberals a plug, but one of the parties that I'm aware of as part of its election platform has stated they will reduce the territorial tax rate from 15 percent to 12 percent if they are elected.

So I'm not -- not aware of what the two other parties have or have not said, but I did note that that has occurred at least with regards to the Liberal Party platform.

And this is part and parcel of why we were -- are requesting it. We don't know what's going to happen after the election. The territorial rate may go up; it may go down.

Q. Okay.

A. MR. GRATTAN: At least one party is promising that it's going to go down. 09:44

Q. Do you have a view, sir, on how likely changes would be to occur in 2017, given the fact that there may be a new government?

A. MR. GRATTAN: How likely? Well, I can -- I can say in -- well, how likely? I don't want to speculate. I'm not supposed to be doing that.

I can state in Alberta when a new government got into power, the following year they did make changes in tax -- in provincial taxes. So it can happen within the following year. So if that answers your question. 09:45

Q. Thank you, Mr. Grattan.

I would like to move to capital additions, which is Section 9 of the application. And I would like to take you to the IR response to the City of Whitehorse

in Exhibit C3-4. And the IR response is the first one, actually, 1(a). Sorry. It's B-4. And, yeah, so CW-YECL-1(a).

On page 1 of the IR response in the second paragraph, ATCO Electric Yukon submitted that: (as read)

"Controllable capital was within 3.2 percent of that approved as part of YECL's 2013-'15 GRA."

Can ATCO Electric Yukon explain what is meant by "controllable capital"? 09:46

A. MR. MASSIE: Sure. What we were trying to show in that table, again, was the -- the difference with the new extension forecast from the actuals. So we looked at our total capital program from '13 to '15, the actuals to approved. There was a large variance between that. And what we wanted to do was focus or pull out the fact that new extensions was a big part of that variance.

And the fact that in new extensions being customer-driven projects, we really have little control over that. We have an obligation to serve when they're ready to dig in their next stage of Whistle Bend -- I use that one because it's the big new development that is out there. We serve it. 09:47

Obviously that changed in the last test period. So, really, with that table, we were looking at pulling that part out, the things that are outside of our control.

Controllable capital really is our -- the remaining distribution generation. In general are GP&E projects that are driven by us. We have full control of those projects. So we consider those -- those are the ones that we really should be -- that we want to measure ourselves against. 09:48

Q. Okay. And in consideration of the ones that are non-controllable capital, such as Whistle Bend, how much control do you have over timing or costing those types of items for what you call "non-controllable capital"?

A. MR. MASSIE: So the control over -- sorry, the costing?

Q. Or the timing.

A. MR. MASSIE: Well, we do have our meetings with the developers. We will flag our -- any constraints 09:49 **that we have out there with our labour force or with contractor labour force that we see.**

But, really, in the Yukon, the -- the construction season can be fairly short compared to other locations, just for the -- these subdivisions -- well, again,

specifically for Whistle Bend, it's an underground subdivision. So it's -- you dig in everything. So really doesn't work well throughout the winter. They usually start their projects in the late spring in the Yukon; so April, May.

We are -- so as those projects go, the developer will be in there. They'll have their civil contractor in there digging in deep utilities, water, sewer, building the streets. So until they get to a certain completion point, there's just no point in us being in there trying to do our work. 09:50

So it really is -- we flag our concerns. We meet with the developers. We talk with them of what's ideal for us. I can guarantee you we don't always get what went. Big projects like that can -- can move and shift the timing. And given how the first stages of those projects go will dictate when we are available to go in there and do our work.

Q. Okay. And in terms of costs, Mr. Massie?

A. MR. MASSIE: So the overall cost of the project, again, we'll sit down with the developer and the design of the subdivision. They'll give us their lot layout, their street layout. We start working on the electrical design of the subdivision and those streets. We really -- we really don't have a lot of 09:51

control in the costs of that project. They'll -- they'll lay out their streets; we'll come up with our design. This is what -- they'll dictate, you know, what they're looking for. We will supply them options. They're usually not -- there isn't a host of options for them. It's pretty straightforward.

When we light up a street to the lighting standard that needs to be, it's very well confined to a standard, so I would say there isn't much control we have over the costs that the customer is going to be mostly contributing to the project. 09:52

Q. Okay. And maybe I'll ask it this way, Mr. Massie. You would have some control over the equipment or maybe the hardware that you're using, those types of things? Do you ever have those discussions on maybe using something that's more cost-effective?

A. **MR. MASSIE: Oh, yes. In that manner, yes. We definitely do have our standards for -- for cables, for transformers, for equipment of that nature.**

When we start talking about streetlights, for instance, we've had discussions with the developer about the next phases and the LED options of streetlights. We've given them a number of options that are available that we can find to supply them with. It really -- it really comes down to their final 09:52

choice of what -- what is going to be installed in that -- in that subdivision.

So, again, we're -- we have, you know, our set amounts of investment with -- for streetlights and the loads for the terms and conditions, but they are going to dictate what they want. We'll give them options, but in the end, they will -- they'll be selecting the options.

Q. Okay. And in preparing your 2016-'17 forecasts, and, in particular, for the new extensions forecast, how does ATCO Electric account for the specific customer requirements in determining your forecasts? 09:53

A. MR. MASSIE: So when we look at it, we have one line item for Whistle Bend Stage 3 in 2017. That number is really based on their design as proposed for the subdivision. Again, we've submitted our electrical design. There could be changes by the time 2017 construction season starts, really, again, their discretion.

The top lines there within our overhead services and underground line extensions, really, we build those based on our recent -- recent years of actuals. So we look at what has happened in the last test period for actuals. We, again, try to forecast, as best we can, when these stages will open up and when the uptake from 09:54

customers will be.

It's -- there's a lot of inputs into the equation that are outside of our control, which makes it a difficult process for sure to -- to forecast and nail down. But the -- we do work with those developers to understand when the lots will be available. And, again, looking in the rear-view mirror, basing it on our recent historical actuals is the blend of what -- how we come up with that.

Q. Okay. And maybe some specific numbers may help us understand, Mr. Massie. I'm going to take you to Schedule 2.1 of the application, Exhibit BB-1(a), and it's the GRA schedules, 2.1. 09:55

A. MR. MASSIE: I am there.

Q. Okay. And in that schedule, sir, with respect to 2014-'15, the Board notes that the number of actual residential and commercial customers are very close to forecast.

And now I'm going to take you to Schedule 9.2, which relates to new general overhead services for various subdivisions and new underground line extensions. And we see in those line items for the same period that the amounts are less than forecast, approximately 2.5 million in '13, 2.5 million in '14, and 3.3 million in '15. 09:56

So given the context of those accounts, can ATCO Electric Yukon provide an explanation regarding the overforecasting of new extensions for 2013 to '15?

A. **MR. MASSIE: So in those accounts, not only the -- do we try to forecast the uptake of new subdivisions -- and you note in 2014 was the first forecast for the Whistle Bend Stage 3. That was to be put in in '14. Obviously, things changed with the developer, so that stage of that subdivision didn't progress at that time.** 09:58

So not only do we try to work with them to figure out when new lots will become available. As of recently, in the city of Whitehorse with -- along with the densification of the downtown core, there has been a -- changes to bylaws to try to allow people to have garden suites in the back of existing properties. We try to -- you know, when we put that forecast together in '13, we try to forecast, as best we can, not only the new subdivisions that open up, but we also base it on the recent historicals. And, again, if we look at 09:58 **the -- and I believe it's UCG-38, the new extensions in 2011 were in $6 million range. In 2012, they were almost $5 million.**

I should bring that up before I carry on.

Yes, there's a table UCG-38(d), as in David.

Q. I'm there, sir.
A. **MR. MASSIE: Yeah, and, again, the combination of looking forward, as well as blending with the historicals, you know, we had some fairly significant years in 2011 and '12 at that 6 million and the $5 million approximate averages, so we looked at those recent historicals, looked at what was coming before us and put that forecast together based on that.**

The correlation to the actual number of customers that have been added -- I can't really explain the correlation, as you pointed out in 2.1, how they're fairly similar, but there still is that drop in new extensions. 09:59

Q. Okay.
A. **MR. MASSIE: So, yes. Again, looking at those historicals, forecasting going forward, one of the things we do in those -- in new extensions, which is invested into, is the streetlights. I would imagine that would be part of the variance. If there isn't as -- you know, if that stage of Whistle Bend is not developed, there will be no streetlights in there either to invest in, just the individual customers. Those numbers are lumped into new extensions also.** 10:01
Q. Gentlemen, and anyone who wants to weigh in on this question, as you're well aware, the City of Whitehorse

has evidence on overforecasting in this proceeding at Exhibit C3-3.

And, Mr. Tenney, you and I talked about this a little bit this morning in terms of O&M, but when we get arguments on overforecasting, what factor should the Board consider in looking at how to deal with issues of overforecasting, either as a general reduction or by account?

A. MR. TENNEY: I'm not sure I'm going to give you a great answer about what issues you should consider, but the one thing for us, I think that we've said continually here -- and Mr. Massie's talked about it -- is overall over that three-year period we think in total that our forecast is pretty accurate. 10:02

And, as you've pointed out, you went through a number of line items. You can pick line items where we're high or line items where we're lower, but overall is what we're most focussed on, not by individual line item.

And I think that fits with some previous Board directions that certainly I know when I look back at 2014-06 where the Board talked about FTEs and said, you know, it's not -- it's not up to us to decide where those are cut. It's here's the cuts. You figure out what positions you really need to cut and which ones 10:02

you need to fill.

And so that's the way we look at that in total, is we're going to need to manage our O&M in total, not necessarily by line item.

Q. And, similarly, for capital projects as well?

A. MR. TENNEY: With the exception that there are capital projects that are customer driven and with our obligation to serve, we think those are a given that they need to move forward.

There's others, as I've mentioned in the last couple of days, safety items, those are for us givens that we need to move forward on them no matter what, and then there's some discretion when you get past that. 10:03

Q. Okay. On --

A. MR. MASSIE: I would just say, you know, I agreed with the operating accounts. And just speaking specifically to the capital program and specifically to new extensions here, we have realized that, you know, we missed the mark in new extensions for that test period. I'd say that we've reflected it in our '16 and '17 forecasts. 10:04

And, you know, when we -- when we saw this and we looked at our forecasts and even for '16, you know, this is one thing we've been tracking a little bit

closer to see how we're doing to see if it made a difference what we've adjusted.

And so far in '16 we're -- you know, we're forecasting to be right close to that, that number that we forecast at the beginning of the year.

Q. Okay. And just moving back to O&M again, Mr. Tenney, you know, when you look at individual line items and adjusting your forecasts for things that might have been over, can you just give me a sense of what you do? What does the company actually undertake when reviewing those accounts to make adjustments when you see some things vastly over or vastly under? 10:05

A. MR. TENNEY: I'm going to hope that Mr. Massie jumps in on some of the individual bits, but I obviously -- the first place you're going to start with is why are you over or under. You're going to need some variance explanations to figure out what exactly had been happening and what you can do to rectify that or if you need to rectify that or if you're over or under where you're going to make up for it. 10:05

So I think those are kind of -- I don't know if that's exactly what you were looking for.

Q. Okay. I'm just -- from a pragmatic perspective, that helps. You've got to look at your inputs.

You know, maybe Mr. Massie can give us some more

things that you look at.

A. MR. MASSIE: Yeah. You know, when we -- we sat down in the first quarter this year to -- to really build this forecast for '16-'17. We sat down, first, you know, going through the variances of what happened in the last -- where our forecasts ended up and explaining each one of those variances.

Whatever changed is that going to continue on. That's what we start with. We also -- we've sat down and went through this line by line and say, okay, these historical costs. Are these accurate. Are they going to continue. And then we put a different -- different additions or reductions in there for certain things that we know are coming or popping up in the maintenance, such as that dam safety review that I mentioned. We know that's coming; that's a known. So we plugged that into the forecast. 10:06

So, yes, we do sit down. We go through these line by line, analyze them with a look at the historicals, looking at our labour force, and any of the known maintenance items that will be added to it, such as diesel maintenance and generation. The -- there's -- in there are top end or minor overhauls, are in there. Those are fairly lumpy expenses. So we forecast those out and add those into our forecasts. 10:07

So there are the knowns, and we plug those into our forecasts.

Q. Okay. Thank you.

MS. SABO: Mr. Chairman, since we started early, this would be a good time for me to break, but I'm okay to continue into a new area. It's up to you.

THE CHAIR: Well, we were thinking maybe 10:15. So we're close enough to that. So why don't we break now for 15 minutes. So we'll come back at 25 after 10:00. 10:08

MS. SABO: Thank you.

THE CHAIR: Thank you.

(ADJOURNMENT)

THE CHAIR: All right. We will call this hearing back to order. And are we -- we don't have any materials just now?

MR. WILLIAMS: No, sir, nothing arising.

THE CHAIR: All right. So we'll just carry on with Ms. Sabo.

MS. SABO: Thank you. 10:30

Q. Mr. Massie, before the break, we were talking about new extensions, and you used streetlights as an example while we were having that exchange. And I just want to confirm that, in Schedule 9.2, new extension and street lighting are different capital expenditure line items.

That's right. Yes?

A. MR. MASSIE: Yes, in Schedule 9.2, that's correct, yeah.

Q. So we just wanted to make sure that when you were explaining the reasons for the variances and new extensions, that wasn't part of that response. You were just using streetlights as an example of an area where there could be variability.

A. MR. MASSIE: Yes. Because -- yeah. Very good point. It's not part of new extensions. Its own appropriation. But in new -- or in streetlights, there are -- our driven projects -- our projects, as well as customer-driven projects. So very similar to new extensions. 10:31

Q. Okay. Thank you.

And can you undertake to provide an update for your new extension actuals for 2016 that are available to date?

A. MR. MASSIE: Yes, I can undertake to provide.

Q. Thank you, sir. 10:31

UNDERTAKING - TO PROVIDE AN UPDATE FOR YOUR NEW EXTENSION ACTUALS FOR YOUR 2016 THAT ARE AVAILABLE TO DATE

Q. MS. SABO: I'm going to start out in capital projects with some follow-up questions on the

studies -- the various studies that have been already discussed over the past few days. And I'd like to start with the study for the Watson Lake project.

I want to confirm that there's not going to be an additional study for Phase 2 of the project. That all of the study costs will be in the previous study?

A. MR. TENNEY: That's correct.

Q. Okay. And at a high level, Mr. Tenney, can you summarize the results of the Watson Lake LNG study for us? 10:32

A. MR. TENNEY: Can I summarize the results?

Q. Yeah. What did you find? We have costs incurred. What do those relate to, and where are we at?

A. MR. TENNEY: I know there's an IR on it, and you just have give me a second to try and find it where we described everything that was done in the study. So...

I'm not sure I'm going to find it right now. I will look. But the results of all of the feasibility studies that we've done to date on Watson Lake, there's 10:34 **a number of things that we had to understand from the fees -- the economic feasibility of it, the technical feasibility of it, and the environmental feasibility of moving forward with the project.**

We had to go down a lot of avenues because, when

we were first working on the Watson Lake bi-fuel project back in the earlier 2013-2014 time period, it, of course, was the first of its kind. And so there really were no -- there were a lot of new policy that had to be developed by the Yukon Government. We needed to understand better the technical bits to it, had to understand the safety issues that arose from it.

So there was a number of things that had to be understood in those feasibility studies. Ultimately, though, it resulted in us bringing forward -- it -- the results were positive, in that we moved forward with the project in the 2013 to '15 GRA. 10:35

Q. And how did those results shape the recommendations for Watson Lake Phase 1 and Phase 2?

A. MR. TENNEY: Well, again, I think -- I think this is where you're going, hopefully. Back then we were the first LNG project in Yukon, and so one of the things that came forward out of that, through the YESAB application, was that we needed to -- weren't sure what the final results of the omissions. So there was testing that needed to be done after Phase 1 was complete before we moved forward with the other five engines. So that partially shaped how we moved forward. 10:36

But overall, we still -- you know, it -- we

decided to move forward with all six engines being converted. At the time, based on some of those, we had structured it to use an affiliate company that had some expertise in the design of this that we didn't have. So that was part of how we moved forward at the time.

Obviously we've since changed that, partially as a result of Board Decision 2014-06.

Q. And with respect to just the study, how should the Board assess the prudency of the costs? You said, you know, it was the first of its kind. Can you give us any more detail on how some of those items flowed into the ultimate costs for the study? 10:37

A. MR. TENNEY: I think all of those costs flowed into the costs of the study. And for me, I was quite happy when I read previous Board decisions where they recognized that, as a utility company, if we're going to try to get off diesel in some of our communities, we're going to have to expend some resources to try to find those alternatives.

And I think that's good news, because not all of the things that we look at that we study are going to turn out to be projects. And so if all we're left with is taking a risk with no chance to recover those costs, it's certainly going to make you think twice about whether you're going to pursue any alternatives. 10:37

And so this one, I believe, we're fortunate in that the studies have resulted in a project that we think is viable. And so think -- in our application, we've currently asked for those to be in deferred charges. And I think that we've acknowledged that just as easily we would be happy to put those into rate base just as well.

Q. Okay. Thank you.

And I'm going to -- I'm going to go back to Watson Lake more specifically later, but I want to keep it on the studies for now, Mr. Tenney. 10:38

Can you confirm whether the joint smart grid study is a stand-alone project, or does it fall within the renewable and alternate energy feasibility study? And the reason why we're asking that question is it appears on the GRA schedules, specifically, Schedule 8.8 -- and that's Exhibit BB-1(a), Schedule 8.8 -- that the joint smart grid costs at line 75 -- it's line 75, are separate from the renewable feasibility study. And the renewable feasibility study is at line 67. 10:39

A. MR. TENNEY: So I'll start, and Mr. Massie may have something to add, but certainly, in my mind, they're two separate studies. When we're looking at renewables and alternate energy study, that's separate from the smart grid study.

The renewables and alternative energy study is strictly ATCO Electric Yukon working on that project. The joint smart grid study is just that, joint. It's with Yukon Energy Corporation. So I see them as two totally separate projects.

I agree that, like many things that we do, the eventual outcome of both of them might be to help us reduce dependancy on diesel, but they're looked at differently.

Q. Okay. And why is ATCO Electric Yukon recommending the joint smart grid study be conducted in 2017 rather than '18 or '19? 10:40

A. MR. MASSIE: We -- basically, that year was a result of sitting down with Yukon Energy and coordinating our resources: Really, what is the best timeline to put it together. And that was the thought for '17 is where we ended up in for our joint discussions.

Q. Could it be deferred to '18?

A. MR. TENNEY: It's hard for us to say, speaking on behalf of both companies. What we had agreed on is we were going to move forward in '17, and we certainly want to do it in lockstep, since we're so tightly tied together. So if we say sure and we don't get costs included in revenue requirement and they say no, then 10:41

we're in a tough spot again.

Q. With respect to the renewable and alternate energy study, can you explain -- and Ms. Middler talked about this a little bit yesterday, and I think I understand -- I know what the answer to this is, but I'm going to ask it anyway because it wasn't clear to me.

So with respect to that study, why are renewable -- renewables and alternate energy being evaluated through both a pre-feasibility study and then a feasibility study? And I thought I would -- what I heard yesterday was is there wasn't a strong distinction between the two, but I'm not sure, so can you help me out with that? 10:42

A. MR. TENNEY: Yes. I get tripped up on what those titles exactly mean. But in my mind it's just, when we get some third-party help to guide us, I don't want to waste time on a detailed study if they know right away that there's no renewable resource in the area or if they know straight away that the economics or the technical or the environmental considerations are just going to result in a no chance for a project. I don't want to focus resources there. I'd rather focus them where there's more of a chance. 10:42

So that said, I still think they're probably the

same study. It's just a quick glance, and then let's get into it in more detail.

Q. Okay. So would it be fair to say, Mr. Tenney, that a pre-feasibility study, you would do some preliminary work, and then that work may be rolled into the final feasibility study?

A. MR. TENNEY: Or we stop on that community. Agreed.

Q. Okay. If it was not feasible.

A. MR. TENNEY: Correct. 10:43

Q. Are you aware, gentlemen, at this time of any further funding opportunities for projects stemming from the renewable study from either the Federal or Territorial Governments that may be known to you or have been -- become public since you filed your application and your IRs?

A. MR. TENNEY: Again, in one of the information responses, we did talk about the last -- the 2016 federal budget that they earmarked, I believe it was $10.6 million for renewable energy programs. We have 10:43 **been working with the Federal Government to see if we can access that.**

To date, the message -- and I think we -- in one of that -- October 24th, I believe it was, update that we did, we had originally said that we hadn't included

the watt -- we weren't seeking federal funding for the Watson Lake bi-fuel project, but we did through the Canadian Electrical Association. The ATCO Group of Companies was participating with them and did submit that project in looking for funding.

What we got back -- what I understand we got back from the Federal Government is right now they were looking for projects that were farther along. In fact, they were looking for projects that were shovel ready. So they weren't looking to fund more feasibility studies. They were looking to help make the project -- the economics work to get it under construction.

So, to date, we haven't found any funding, but that doesn't mean we're not going to continue to try and access some.

Q. Okay. And Yukon Conservation Society asked you yesterday about alternatives in order to deal with fuel concerns at Watson Lake other than what you've proposed with this project. We just wanted to know, have you ever looked at other alternatives to managing that site other than the move to biofuel?

10:44

10:45

A. **MR. TENNEY: Well, we're obviously looking at some right now, which is the renewable and alternative energy study. As I mentioned to Ms. -- I believe it was to Ms. Middler, we were for sure involved with the**

Liard First Nation and the Town of Watson Lake in looking at hydro -- we're looking at hydro sites in the area, and certainly have a report completed on that.

I know we've been in conversations with -- I'm going to say it's mostly with the Liard First Nation, but it might be with the Kaska in total, about looking at geothermal-type projects as well. We have had some consideration on others.

Right now what we're looking for moving forward with in the near term is taking a look specifically more at solar and wind generation. We're not ruling out anything, but in the early days, we want to first look at those two. 10:46

Q. Okay. So that's longer term? You would still need the business case as proposed in this application for the shorter term?

A. MR. TENNEY: If we moved forward on hydro or geothermal, we for sure would need to be coming back to this Board. Those are significant projects with significant upfront resources required to determine feasibility. 10:46

Q. Okay. Continuing on Watson Lake. And, Mr. Tenney, and the panel, I might be bouncing around a little bit I'm going to get into some more specifics and then go back to the high level, because there's a lot of information

throughout the file on this project, and the Board's just trying to get their head around the project in total.

So can you confirm for us if the Watson Lake biofuel costs for Phase 2 have been grouped together with some of the costs for Watson Lake Phase 1? And specifically, I could take you to Schedule 8.8, because it only appears on that schedule, that the study costs were identified in there. So I'm just trying to get an idea of that -- in that schedule, that's the total study costs for Phase 1 and Phase 2. 10:47

And that's Exhibit BB-1(a), Schedule 8.8, line 33, I believe.

A. MR. TENNEY: My reason for searching around a little bit is I see the numbers there, but I have a different number in my head, and I just want to quickly look at YUB-13.

Q. Thank you, Mr. Tenney. I'll pull that up as well.

A. MR. TENNEY: I'm not sure I'm going to get anything there, but that's where I... 10:49

Yeah. We identify on -- that's the revised economic -- that's the revised table showing the capital costs for Phase 1 and 2. So I'm not page 2 of 6 of that IR.

Q. Yes, I'm there, sir.

A. MR. TENNEY: You can see from there on the very left-hand side, we had study costs identified of 222,000, and then additional engineering design and permitting work done in -- between 2012 of '15 (verbatim) of 272.

And so I guess I'm going to need to just check. I thought the whole amount of 494,000 was what we had in study costs.

Q. Okay. If you could undertake to do that, Mr. Tenney, and just let us know what the Watson Lake study costs include and what the total amount should be in 8.8. And if you need to revise the table in the IR as well -- that's IR 13. 10:50

A. MR. TENNEY: I will do that. I was just hoping you were going to stay at a high level for a lot longer where I had a chance.

Q. That's fine, sir. Thank you.

UNDERTAKING - TO PROVIDE WHAT THE WATSON LAKE STUDY COSTS INCLUDE AND WHAT THE TOTAL AMOUNT SHOULD BE IN SCHEDULE 8.8 AND IF THE TABLE IN IR 13 NEEDS TO BE REVISED 10:48

Q. MS. SABO: In the previous GRA decision, Board Order 2014, can you confirm that the Board directed that all project costs related for Watson Lake

be removed from ATCO Electric's proposed 2013-'15 capital additions?

A. MR. TENNEY: Yes. I believe they told us to leave them in work in progress because -- I'm not exactly the exact words -- but I thought they seen some potential for this project.

Q. And in compliance with that decision, I also understand ATCO Electric Yukon is stating that they have applied for this project again in the current GRA because the contracting issue with affiliate services would be avoided. Yes? 10:51

A. MR. TENNEY: Well, we didn't just file for just that reason, but that was our interpretation of the Board decision and that was a major concern of the Board's during the last GRA. But we noted that the Board still thought the project had potential.

When we reviewed all of the economics, and, again, our obligation to serve with reliable, cost-effective service, together all of that brought us back to where we are again today with us asking for this project to be approved. 10:51

Q. Fair enough, Mr. Tenney.

How did ATCO Electric Yukon determine that the transfer of assets from ATCO Gas for the Watson Lake project would be the alternative that would best

support Phase 2 of the project and the project costs?

A. MR. TENNEY: So the question, again, if I understand it, how the purchase of the assets from ATCO Gas would benefit Phase 2 of the project?

Q. I'm just wondering why you chose that as the solution to resubmit the project to address the Board's concern in Board Order 2014-06?

A. MR. TENNEY: Okay. So I'll try. I think if I understand the question. In the last go-around of the project, we had ATCO Gas as the affiliate that we were going to lease a lot of the equipment from. And our understanding was the Board thought that there wasn't enough competitive pressures put on that lease arrangement. 10:52

What we do know is we participated with ATCO Gas when they selected the equipment that was designed specifically for Watson Lake, and they ran a competitive process.

So we knew that there was value there.

Subsequent to that, when we filed the R&V -- before we filed the review and variance of the 2014-06, trying to address some of the Board's concerns, we had a third-party help us conduct a competitive process where we went out to -- there were more players in the marketplace at that time than there were when we made 10:53

the original application. So we ran a competitive process looking for either a lease arrangement or an outright purchase. We had three bidders, including gas, and ATCO Gas still ended up with the lowest price.

Those things lead us to believe -- that and the fact that ATCO Gas is going to transfer those assets that they purchased back in 2014 at their net book value, so at cost, we felt that made sense to us. All of those things taken together lead us to believe that was a prudent decision. 10:54

Q. Okay. And that competitive process led you to the conclusion that the cost of the assets transferred was done at a fair price because it was net book value; yes?

A. MR. TENNEY: Well, they were the lowest bidder in the competitive process. So that's one. And we know they've shown us their books as to what the net book value is for those assets. So that's two. Those were the reasons.

Q. Did any of the other bidders also look at what those assets would cost if they were to be successful in the bid process -- excuse me -- in the bid process? 10:54

A. MR. TENNEY: I'm not -- so as Mr. Grattan is pointing out, the competitive process and the results thereof showed what the bids were. So the Board has

that information, and I'm pretty sure it's on the record here in one of the IRs, I think, to the City of Whitehorse. We filed that review and variance application.

So -- but I don't -- I still don't know if I'm answering your question, because other two bidders didn't have access to look at ATCO Gas's numbers or the other bidder.

Q. Yeah.

A. MR. TENNEY: They just knew they were in a competitive process, and they submitted their bid. 10:55

Q. Fair enough, Mr. Tenney.

What I was trying to get at is how do we know that the assets purchased are transferred at net book value from ATCO Gas is a representative or the best price or the best asset to be used for the project? So can you help me out there?

A. MR. TENNEY: So I'm -- we're probably missing each other, because I'm probably just going to repeat what I said. In the R&V -- just prior to us submitting the R&V, we ran a process said, here's our specific requirements for our Watson Lake bi-fuel project. Can you tell me what you would submit a bid for to supply those assets. 10:56

Q. Okay.

A. MR. TENNEY: And ATCO Gas was the winning bidder.

Q. Thank you, Mr. Tenney. I think I got there.

Are you able to specify exactly what ATCO Electric Yukon is seeking approval for with respect to the Phase 1 portion of the project? Are we looking at the business case, the capital expenditures, the capital additions, or all three?

I can maybe give you a reference, Mr. Tenney, on why we're asking this the question. It's -- the application Appendix 3, Exhibit BB-1. And, like I said, it's Appendix 3 of the business case, pdf page 243. 10:57

A. MR. TENNEY: Our trouble on this side is we have a different pdf.

Q. Oh, yeah.

A. MR. TENNEY: So our numbers aren't quite the same.

Q. I've seen that before.

So what I'm looking at, it's a passage that says: (as read) 10:58

"The Watson Lake bi-fuel project achieves the Federal and Yukon Governments' goals of displacing diesel and managing electricity costs by..."

And then there's two numbered items and after that it says: (as read)

"ATCO Electric Yukon estimates the total cost of the three-year project to be approximately 4.97 million; however, at this time, ATCO Electric Yukon is seeking approval for 3.26 million to implement Phase 1."

A. MR. TENNEY: Right. I see that. But I know there's an IR, and I probably should try and find this one. 10:58

Q. Is that the one with the table, sir?

A. MR. TENNEY: That's the one where we were asked the same question: What is it that we're asking the Board to approve?

Q. Yeah.

A. MR. TENNEY: We're asking the Board to approve the project. So I guess, in your words, that would be to approve the business case. At this time, we're asking the Board to approve our 2016 and 2017 revenue 10:59 **requirement, plus our capital additions for 2016 and '17. So under that words, we're asking them to approve the Phase 1 capital costs and associated O&M and fuel, and the 20 -- the Phase 2 part of the project which is to be built in 2018, that will have to come at a later**

time.

Q. Okay. And Phase 1 and 2, are these phases just for the conversion of the diesel units, or is there something else that's going to happen within those business cases -- or within those phases?

A. MR. TENNEY: So in Phase 1, we would have to move them -- move the majority of the equipment on site, and, you know, the LNG, the liquefaction, and the -- sorry, the storage, the large storage, and the regasification equipment. We would only convert one 10:59
engine to bi-fuel. Then we'd do the testing with Yukon Environment. And then on Phase 2, we talk about a second storage tank and some additional offloading facilities and the conversion of the other five units.

Q. Okay. And is there expected to be another phase after that work is complete? Just trying to get a sense of if the project costs we're seeing here for the test year is in -- understandably in 2018, because you've provided those as well. I'm just wondering if this is going to be a running cost, or there's going to be 11:00
another phase, or if you kind of expect this to be the end after Phase 1 and Phase 2 are completed.

A. MR. TENNEY: That's the end, as far as I see it. That would have all six of the existing units converted to bi-fuel mode.

Q. Okay. And I believe I saw in an IR -- and you can correct me if I'm wrong, because I didn't go back and pull it yesterday. In one of the IR responses, I thought you said in this proceeding you're looking for approval of both Phase 1 and Phase 2. Is that correct, or are we just looking at Phase 1 here?

A. MR. TENNEY: So that's, again, what I -- that's the same IR that I was referring to, and what my words are to one of your questions a few moments ago, we're essentially looking for the Board to approve the project, -- so, in your words, the "business case" -- which would mean they agree this makes sense in total. But we're just asking for the inclusion in revenue requirement of the equipment that's -- or the capital cost and the associated fuel and O&M costs for Phase 1. 11:01

Q. Okay. And if the Board were to approve the project in the decision that would, say, come out in Quarter 1 or Quarter 2 of 2017, would you -- when would Phase 1 expect to be completed if the project is approved?

A. MR. TENNEY: Depending exactly when the decision comes out, but what you kind of said there, I think we would expect it to be in service late in 2017. 11:02

Q. And the other thing, between Phase 1 and Phase 2, we notice that the majority of the costs, which are in 2017, the majority of the costs that make up the

$3 plus million for Phase 1 are basically related to Phase 1, which is one unit. And then we've got Phase 2, which is about 1.7 million, which is for the additional five units. And we were just looking at that and thinking the majority of the costs seem to be in Phase 1, so why is that the case, that it's so much more expensive for Phase 1 than Phase 2?

A. MR. TENNEY: Right. You're probably going to get me quickly over my head, but in terms of the storage of the actual LNG, you've got a large storage tank that's -- it's -- the size is bigger than just what's required for one engine. So -- and then the actual gasification, so when you take that LNG, the liquid natural gas, and heat it up and turn it back into gas, that's also included all in Phase 1.

Q. Okay.

A. MR. TENNEY: So there's a lot of costs that are common costs, but they're incurred upfront.

Q. Front. Okay. Yeah, and that's what we understood, because it's the LNG vaporizer and LNG storage tanks that are 1.47 million in Phase 1. 11:03

A. MR. TENNEY: Yeah. I think the only caution I have there is you're using the original numbers, the 1.47. That's been reduced to 11, 94. In that YUB-13 we --

Q. We were at.
A. MR. TENNEY: Right.
Q. Thank you. So if the Commission were to approve Phase 1 but did not determine Phase 2 in the decision that's going to come out as a result of this proceeding, what would be the response of ATCO Electric Yukon in types -- in terms of the decision-making on whether to go ahead in converting all units; right? If we only say, well, we'll look at Phase 1, but Phase 2, we'll see how Phase 1 goes first, and then we'll look at Phase 2 later. Can you give me an idea? I know it's speculative, but can you just give me a sense if that would be viable and why or why not? 11:04
A. MR. TENNEY: Well, I guess my first -- as you would guess, it really depends on what specifically the Board says. But it certainly gives us reason for some caution because a lot of the costs that are in Phase 1, in order to make this project economic, you need all six engines converted. And if we spend a significant chunk of capital and only have one engine converted, the economics aren't there for our customers. And so that's challenging -- I suspect challenging for not only ATCO Electric Yukon, its customers, but also the Board. Because we moved forward on this initiative because we felt it was an economic project. And if we 11:05

didn't do both phases, we wouldn't have an economic project.

Q. Okay.

A. MR. TENNEY: So it does give us pause for caution.

Q. Okay. Thank you, Mr. Tenney.

Now, I've got some more accounting questions on Watson Lake, and, Mr. Grattan, or anyone on the panel, can you tell me what account number these diesel costs are recorded in? There was some testimony yesterday, 11:06
and we weren't sure if these were recorded in a generation account or somewhere separately. We think maybe Account 445, but if you could help us out and let us know what account the diesel units would be in, that's great.

A. MR. GRATTAN: I'm going to say, subject to check, the components that relate to the diesel generators tied to this project would be in 445, but I'll take that under subject to check.

Q. Thank you, sir. 11:07

A. MR. GRATTAN: Yeah. Mr. Tenney just reminded me that it could go to a number of different locations.

Q. Okay. And --

A. MR. GRATTAN: So that's why I was specific with respect to the pieces that are being added to the

diesel engines to facilitate LNG.

But if you're talking about the vaporizer and the infrastructure to get from the vaporizer into the Watson Lake plant, that would be potentially a different answer.

Q. Okay. I think it's sufficient if you can just take your subject to check, Mr. Grattan, rather than all the other components.

A. MR. GRATTAN: Fair enough.

Q. Thank you. 11:08

I'm going to take you to Exhibit B-9, and, again, that's the responses to the Board. And I'm looking at 29(g). And I'm looking at page 3 of 3 of the hard copy of that IR response.

And 24(g) asked about the original historical cost and accumulated depreciation related to the assets being purchased from ATCO Gas. And ATCO Electric Yukon responded on page 3 of 3, Part (g): (as read)

"This equipment has never been put into use, and as such, no depreciation has 11:09 been accumulated. The original historical cost, accumulated depreciation, and net book value shown below."

And, again, that's the number that Mr. Tenney referred

me to of 1.194 million.

So can you confirm, were the assets purchased from ATCO in contemplation of the Watson Lake bio-fuel project?

A. MR. TENNEY: Were the assets purchased from ATCO?

Q. Gas, yeah. Or they're just being transferred.

A. MR. TENNEY: We have not purchased those assets yet from ATCO Gas.

Q. Mm-hmm. 11:09

A. MR. TENNEY: They're still ATCO Gas's assets.

Q. Okay. Thank you for that confirmation, Mr. Tenney.

Does ATCO Electric Yukon consider that facilities approval for the units in Phase 2 would be required because you're not just replacing one unit, you're replacing several? Do you think that that would require a facilities approval by this Board? Under Part 3 of the Act?

A. MR. TENNEY: I think I'm going to start, and Mr. Massie might chime in. 11:10

Q. Certainly.

A. MR. TENNEY: You said a couple things that -- just to make sure -- and maybe I didn't hear it quite correctly, but you said you're replacing all six units. We're not replacing any units. We're bolting on a

bi-fuel kit.

Q. Yeah. I'm sorry. I should have said "converting."

A. MR. TENNEY: Okay.

A. MR. MASSIE: And just in the relation to the Part 3 under the Act, it's our understanding that that -- the Part 3 is -- you need an order from the Minister. So that's our understanding in getting a Part 3 energy project certificate.

Q. Okay. And I'm sure your counsel will advice accordingly, I just wasn't sure if we maybe have -- have another wrinkle there. So I'll just leave it at that, gentlemen. Thank you. 11:11

Just one more question on the conversion of the diesel units. And, Mr. Massie, this is probably you because it's a fairly technical question.

A. MR. MASSIE: Oh, boy.

Q. How well is an engine designed to burn diesel versus natural gas once you do a conversion? Can you kind of give me a sense what that involves and how efficient that unit will be? 11:12

A. MR. MASSIE: So understanding for the bi-fuel kits that get bolted onto the existing units, it really is -- it introduces a mix of natural gas into the intake air of the unit. So the unit will still need diesel to burn or to operate. And it uses it primarily

for lubrication and cooling, but it's a combination of the both of the diesel and the natural gas.

And my understanding is that the natural gas can have as much as a 70 percent mixture in there. So it would be up to a maximum 70 percent of natural gas and 30 percent diesel. So there needs to be that diesel component still left in there for the proper operation of the unit.

Does that help?

Q. Yes. Thank you. 11:13

And when you put on the conversion kit -- I mean, the unit, I imagine, is modified by the conversion kit; yes?

A. MR. MASSIE: Yes. Yeah. That goes right on the unit.

Q. Okay. And does that affect the warranty or the service life of the unit?

A. MR. MASSIE: My understanding is that it does not modify the warranty. The -- our preliminary discussions are with the manufacturer of the units. 11:14 **And their technicians would be the ones that install it, the conversion kit, that is.**

Q. So would it be expected that the units would wear out quicker, or would they just be able to operate as before and have the same service life? Do you know?

A. MR. MASSIE: It's our expectation that it would not modify the service life of the unit. Yeah. Again, our expectation is that there will be no change in the life expectancy or the wear of the unit. The conversion kits are installed by their technicians. The technology is designed to work with those existing units.

Q. Okay. And if you were to have to replace a diesel unit, obviously -- I shouldn't say obviously -- would it be replaced with a new unit that would -- would be able to operate under both diesel and LNG, or would you also do what you're doing now and use a conversion kit? 11:15

A. MR. TENNEY: So, so far in my discussions and our group's discussions with the suppliers of these equipments, right now the bi-fuel equipment's direct from the factory without a bolt-on kit. So far they're only available in marine applications, and there's not one yet for use at a stationary power plant.

So in the near term, I suspect, we're looking at bolting on the bi-fuel kit. But I suspect if it's available in marine applications, as the demand for it grows, they'll likely make it available for stationary power plants. 11:16

Q. Thank you, Mr. Tenney. That's helpful because it's hard to compare units when they're not available.

I am going to move to the Fish Lake to headpond spillway replacement, which is Appendix 2 of the application at Exhibit BB-1. And I'm in Appendix 2, page 1 of the hard copy, pdf page 239.

A. MR. MASSIE: Page number, sorry, of the --

Q. Sorry. Hard copy is page 1.

A. MR. MASSIE: Okay, yeah, I'm there.

Q. Okay. And just a question general. I'm not going to refer you to anything quite yet, but ATCO Electric Yukon has stated: (as read) 11:17

> "The main driver is aging infrastructure and that the project also complies with the recommendations of the dam safety report."

Yes?

A. MR. MASSIE: Yes, that's correct.

Q. Okay. And then on page 1 it also says: (as read)

> "This project will ensure ATCO Electric complies with the recommendations of the dam safety report and Item 42 of the 11:17 water license HY12-065."

Yes?

A. MR. MASSIE: I'm just -- oh, there we go. At the bottom. HY12. Yes, I see that.

Q. Great. What was the recommendation of the 2014 dam

safety report and Item 2 of the water licence? Can you help us out?

A. MR. MASSIE: Sure, just give me one... Okay. So I'm looking at our -- the dam safety review in Attachment 1 of YUB-14. And the 2014-09 recommendation, as it states here, is: (as read)

"Replace the Dam Number 2 spillway with a new structure within the next three years, i.e., (by 2017)."

In brackets. 11:19

Q. Sorry, I missed that, Mr. Massie. Could you just repeat that?

A. MR. MASSIE: Of course. Let me just roll back. I'll... Do you need the reference page or the --

Q. No, that's fine.

A. MR. MASSIE: Just to read the actual recommendation again?

Q. Yes.

A. MR. MASSIE: Okay. So as read: (as read)

"Replace the Dam Number 2 spillway with 11:20
a new structure within the next three years."

And in brackets it has "(i.e., by 2017)."

Q. Okay. And Item 42 of the water licence, how does that factor in?

A. MR. MASSIE: So Item 42 of the water license is under Part (d) of the water license for monitoring, and, basically, it spells out that we will do a dam safety report on a yearly basis. And so, basically, the water licence dictates that we do these reports, and then the report has the recommendation.

Q. Okay. Thank you. I want to go to the Watson Lake Unit 2 replacement business case at Appendix 4 of the application. And I have a pdf, so it's probably not going to help you, Mr. Massie, but it's pdf pages 251 to 254 where the business case is at. 11:21

A. MR. MASSIE: Yes, I have the business case --

Q. Okay.

A. MR. MASSIE: -- in front of me.

Q. And, actually, I do have the page. It's page 1. It says: (as read)

> "The original scope of the project in the 2013-'15 General Rate Application was to replace the unit with a similar-sized engine, 800 kilowatts. At 11:21 the time the unit tender and selection, capacity requirements were reviewed. This review determined that, in order to meet contingency handling requirements, a larger unit, 100 kilowatts, is

required."

Can you provide me with some detail on why the issue of requiring a larger unit was not known at the time that the Watson Lake business case was provided in the '13-'15 GRA? Why was it only identified at the time of tender and selection?

A. MR. MASSIE: Yeah, okay. So if -- recalling that the last business case we -- we identify the size of the unit that needs to be replaced. And usually that we'll recommend is that we're going to be 11:22
replacing the unit with a similarly-sized unit. The caveat that we have is that when it comes -- so when that business case was built back in late 2012, early 2013, it was forecast to be replaced in 2015. So what we do is when we get to the year that we are replacing a unit is we review the community load at that time.

After reviewing that community load, we -- we select the -- the engine that's going to provide the best -- best complement to the plant to continue to supply the load of the community, as well as that 11:23
combination of efficiency for heat rate.

Q. Okay.

A. MR. MASSIE: So, though we forecast at -- ahead of time what we think that unit will be, when it comes time to replace a unit, we do have to factor in what

we're -- what we're looking in front of us for a load on the community.

Q. Okay. And, similarly, for the Old Crow Unit 3 replacement, you would say the same thing. So that's a general policy?

A. MR. MASSIE: Yes, we do a -- that load analysis, and you'll see in the Old Crow 3 replacement there's a -- there's a community load duration curves. So understand, you know, throughout the year how much time a community spends at a certain amount of load. 11:24 **It will factor in the peak loads. So obviously we -- the peak load of the community can only be -- you know, that peak can be established in a one-minute interval in a year, but we'll still have to supply that peak, so that gets factored in as well. So not just -- not just the peak, but the dispersion of load throughout the year for that community.**

Q. And can you give me a sense -- I know you've provided a lot of information on, you know, the project steps you take when you're building a business case in your 11:24 forecasts, and I'd just like to know a little bit more about the planning phase, given what you've just responded to, you know, later you do an update to see where the load is at.

So when you're planning a project and looking at

your forecasts, what information or what steps are there in the planning phase that you use to develop that business case? Do you have kind of an internal checklist you follow? Is there kind of a standard list of things you look at to try and make your forecasts as accurate as possible?

A. MR. MASSIE: Yes. There is a standard checklist of what we look at. You know, we also factor in, especially in this last test period, you know, we look at the actuals from projects that have been completed. So our estimates at the time are based on what we think the community will need for a unit at that time, what we think the contractors' rates will be, what we think materials will cost at that time.

As we go ahead with projects, like in the later years of that test period, 14, '15, and including this year in '2016, we'll look at the costs that we've incurred in those projects. So we'll have a very informed understanding of what the actual costs were, not just based on a -- on our estimate. We'll look at our actual cost from previous projects that are similar. 11:25 11:26

The one thing that we've found quite interesting with these diesel generators, so when we tender for the supply of the units, it really -- in this last test

period, there was quite a variation in costs based on market demand.

So, for instance, this -- this unit, Watson Lake 2, you know, we knew we were replacing it this year for -- so in the first quarter, when we went to market to get a replacement engine -- and the replacement engine is actually 895 kilowatt engine. That's what's been selected and will be installed here shortly.

But when we got the tenders back, there was actually a unit that was 11 -- 1.4 megawatt. So 1450 kilowatt unit that was offered for purchase at a cost that was below the cost of this unit. And so that -- that surprised us. It was a much larger unit. 11:27

So we contact the manufacturer; but, you know, in that instance, the unit was going to be heading to a mine. That mine is no longer there. So they had a brand-new unit sitting on their floor that they want to do get rid of at a discount price.

At that time, you know, we reviewed that unit to our community load, and it just -- the efficiency wasn't there. You know, we could have, you know, got that bigger unit, but it wouldn't have been run in at a very efficient rate compared to this unit. 11:28

Q. Okay.

A. MR. MASSIE: So there are a number of factors that we put into our model to -- before we start looking at these. However, our -- the interesting part that we've found is that market, even now with the turndown in commodity prices and the mining sector that these contractors supply units for, they're phoning us to see if we need anything now. Whereas in the last couple years, it's been tough getting ahold of them.

So it's just one of those interesting things that we've learned as we've gone along and have been dealing with going forward. 11:29

Q. Okay. And any other checklist items? I mean, I imagine I don't need to get you to do an undertaking to provide the checklist to make sure it's complete.

Anything else you can think of?

A. MR. MASSIE: Well, you know, we look at the cost -- those material costs, our labour costs, what we think from the competitive bid will come in. As we've learned with the -- our Old Crow projects is looking at other community projects in the area that will affect the availability of resources for us. 11:29

So those items are the -- are the ones that we look at. Some of them.

Q. Okay. And do you also look at reliability standards in the area? We know you submit reports to the Board on

reliability and where you've had issues. Does that factor into your business case analysis?

A. MR. MASSIE: Are we still -- are we still talking specifically generation or broader?

Q. More broadly, yes.

A. MR. MASSIE: Okay. Yes. Yeah. The system performance, the plant performance, yes, we figure in -- that into the equation too. Very similar to this Watson Lake 2 unit, the performance of the unit was forecast to be replaced in 2015. The unit was 11:30
operating acceptability within its parameters. There was no issues with it or the community. So it would be replaced in 2016.

But on the distribution side, yes, we'll look at performing feeders, see if there are deficiencies in the system that are contributing to those outages, and that would factor into it also.

Q. Okay. Thank you.

And now back to Old Crow and the business case. I have a confirming question. Is it correct that 11:31
Old Crow's generation plant capacity will have grown from three units with an installed capacity of 1,170 kilowatt hours to four units with an installed capacity of 2,000 kilowatt hours?

A. MR. MASSIE: I can confirm that the new

installed capacity is 2,000 kilowatts. I'll take from the existing, subject to check. Just I don't have --

Q. That's fine, sir.

A. MR. MASSIE: -- the old unit numbers in front of me.

I may have them. Yes. 1,170 that's what --

Q. Correct.

A. MR. MASSIE: Yes. That is correct.

Q. So can you provide an explanation regarding the basis for the increased capacity in Old Crow? Is it just load-based or something else? 11:32

A. MR. MASSIE: So I think when we talk about Old Crow, the overall capacity of the community is -- of our power plant capacity in that community is 2,000 kilowatts now. It's important, though, to understand that these are two separate power plants. They're in the same -- our same lot up in Old Crow, very close to each other. And the new fuel depot really is what confines us to that area.

Q. Okay. 11:33

A. MR. MASSIE: But they're two separate power plants. So we look at them as two -- one power plant at 1,000 and another power plant at 1,000. And it was really one of the big business drivers for our last business case on the Old Crow plant expansion, was to

have full contingency in the event of a loss of a power plant in that community.

So, you know, it's -- it being a fly-in only isolated community north of the Arctic Circle, it definitely is a tough spot for us to have full contingency in our generation as we do in the other communities that we have road access to.

So we have some mobile generators that will provide contingency backup for a community like Destruction Bay or Beaver Creek. If there happened to be a catastrophe and we lose power plant, we're able to roll into that community and have a backup contingency for it. That contingency really wasn't available as readily for Old Crow. That was the business driver around having a second power plant. 11:34

So we do look at those power plants up there as being two separate power plants providing full backup for the other at 1,000 kilowatts.

Does that help at all?

So, yeah, I guess, just the fact that the two power plants there, at the 1,000 kilowatt, compared to the 1,170 that it was before, they do -- they do work in tandem. There is the ability, of course, for two engines in a power plant to be running and a third engine if the community load does grow, which it has in 11:35

the past number of years. And we do have that -- that -- no -- we've seen that peak loading grow and -- and that table is on page 1.

Q. Okay. And you've referred to mobile generators not being as feasible as an option. Is that geography or availability of transport?

A. MR. MASSIE: Availability of transport. We would have to obtain a Herc -- Hercules aircraft to get those units in there. As we've noted in -- or maybe we haven't noted, I've just -- know of it, that we -- for our project that we've completed, the projects we've completed in Old Crow, we've needed a -- to obtain an Herc airplane in the past couple years. When we originally put the estimate together and looked at it, there was a Canadian airline that had a couple that had since got out of that business, so now we had to get a lot of our equipment into Fairbanks, Alaska, to utilize the only Herc that we could find from that side. So the logistics of getting one of those here, get the unit loaded up and to Old Crow would be a matter of days to do. So that really was the drive for that contingency issue of the -- of the second power plant in Old Crow.

11:36

11:37

Q. Okay. What is the expected firm capacity of Old Crow? We're just wondering, for Watson Lake, you provided a

difference between installed capacity and firm capacity. Maybe you could just explain what those terms mean for me first.

A. MR. MASSIE: Fair enough. So the installed capacity is the total amount of our generation that is available on a site. And the firm capacity is -- is that total minus the largest unit. So it's called an N minus 1 criteria. So we're going to -- what we plan for is, if there's an issue and our largest unit is offline, not available, the firm capacity would -- is the capacity we need to ensure that we can supply the community. So in the -- in the example of Old Crow, it would be 1,400 kilowatts would be the firm capacity. Total capacity, again, is 2,000. 11:38

Q. Thank you. We'd like to follow up on the McIntyre subdivision replacement, Appendix 8. And I'm looking at hard copy page 3 of that business case in the application and, specifically, Table 1, when you get there, Mr. Massie.

A. MR. MASSIE: I am there. 11:39

Q. Okay. And I believe that this was with Mr. Rondeau or Mr. Maissan, but there was some discussion of this table. And we wanted to make sure that, when looking at 2013 actuals, there's a construction actual forecast amount of 656, and that's in hundred thousands. So we

wanted to know if that amount is being capitalized, and, if so, what is going into rate base. So it might Mr. Grattan rather than you on that question, but...

A. MR. MASSIE: Yeah, I would take a long time to answer that.

A. MR. GRATTAN: So, sorry, you're asking the question of whether the 656 was put into service? Capitalized?

Q. Whether it was capitalized, yes.

A. MR. GRATTAN: So Mr. Massie's confirmed that that line was in service in 2013, so it would have been capitalized. 11:40

Q. Okay. And what would be going into rate base, Mr. Grattan? Would it be that --

A. MR. GRATTAN: $656,000.

Q. Same amount. So it actually did take both of you to answer that question, so thank you.

A. MR. GRATTAN: Quickly.

Q. I'm going to move to the downtown Whitehorse business case at Appendix 9. And that's at pdf pages 273 to 282. And I'm actually going to just keep that open. I don't know if you'll need it or not. But I'm also going to take you to the response to YUB-YECL-17(g) at Exhibit B-9, page 4 for the hard copy. Again, that's 17(g), page 4, and pdf pages 210. 11:40

And in IR 17(g) it says: (as read)
"With respect to ATCO Electric's system -- sorry -- with respect to ATCO Electric Yukon's system performance optimizations alternative for the downtown Whitehorse capacity upgrade, ATCO Electric Yukon stated the following..."

So the sentence in that IR is: (as read)
"The options discussed under this alternative are still being investigated, as they would be able to provide a short-term solution as load grows in the future." 11:42

So is that still the case, Mr. Massie, or do we have a further update to where that's at?

A. MR. MASSIE: Mm-hmm. So in the items that were looked at for that, that Alternative 3, are on page 7 of that business case. I'm not sure what the pdf number is, and under there are the four bullets that were considered under that system performance optimization. 11:42

Q. I'm just getting there, sir.

A. MR. MASSIE: You bet.

Q. Proceed.

A. MR. MASSIE: Okay. So just walking through those, I guess at a high level, we did look at and consider all these individually in the context of how they could improve the capacity of our -- of delivering our power in the downtown core.

So that first bullet about the optimized substation transformer tap settings and regulators, so the existing equipment there can really be -- we can go and make settings -- change the settings on it so that they will operate right at their maximum and push to their limits. That would provide us with greater capacity. 11:43

However, we're operating equipment at its absolute limits there. So that -- that's really about as far as we've considered that option. You know, it really is an option for us in emergency situations, is how that works.

The dispatch interface, that's tied to the last bullet with SCADA, and that's about understanding our system, you know, in and a realtime fashion. So we'd be able to sit there at the computer, see realtime loads, going in all different directions to understand where it's going. Our answer to any capacity or overload issues would be to switch the system around on a reactive basis. 11:44

So those are things we could still do, and we still consider; but, really, being reactive that way really wasn't considered on a go-forward, long-term basis.

The third bullet there, the installation of additional switches, that did happen. That is part of the proposed option that we've moved with. And I'd say -- and that's captured on page 5 of the business case. You'll see the -- there where we talk about the projects that we've completed in the '16 and '17 test years. 11:45

The main one at the top is the installation of the Selkirk substation, and then the reconductor in the river crossing, and then those bottom three projects are those projects. So we did -- we did move forward with those in -- as part of the solution.

Q. Okay. And given that response, Mr. Massie, do you have any updates to your forecasts costs or the forecast costs for this project still accurate?

A. MR. MASSIE: We've completed the installation of the Selkirk substation. I believe two of those three bullets in the bottom there, in the 2016 test period, for -- two of those are complete. The third one is scheduled to be complete. And they are all forecast to be on those budgets that they're -- in the 11:46

2016 test year.

Q. Thank you.

In terms of the Paint Mountain cable replacement at Appendix 10, if you could pull that up. And I have got a reference of pdf page 210 for those people who are following along.

The page that I was interested in was actually the last page of the business case that has the geographical map on it?

A. MR. MASSIE: I am there. 11:47

Q. And I'm just wondering, with running the cable for the alternate route in red, it kind of goes in a U-shape and up and across the hill and back down.

My question to you is, when preparing this business case for presentation to the Board, why was that the best route? Did you consider alternate routes, or was that the only one available?

A. MR. MASSIE: We did consider alternate routes, and I'm just -- apologize. I thought we had noted that here in this business case. 11:47

So the first one, route that we considered, was the existing one, replacing the cable as it is, in place.

Q. Yeah.

A. MR. MASSIE: We've noted, like -- that's --

basically runs up the rock face of the mountain. Very vertically challenging, I would say. We have no access -- ability to access most of that route, the existing route.

So it's very steep terrain. My guess is that it was installed with a helicopter. There would be no way else to do that. So just given the access issues that we had, that really took care of that concern, or that alternative, I guess.

We also considered an alternative, and it's not on this map, but on the opposite side of the mountain from where that -- the chosen alternative is. Unfortunately, there's no distribution line on that side of the mountain. Again, it's very similar terrain to our proposed route. So the proposed route we actually can access. We can hike that and be able to access that cable. 11:48

On the other side of that mountain, there's very similar terrain that we would be able to access; however, the distribution line is not at the bottom there. So we would have to build a couple kilometres of distribution line. So that put that out of the cost-effective range compared to the proposed route. 11:49

Because you'll see at the bottom there, the blue line, that's an existing power line that we would be

hooking into to go from there.

Q. Okay.

A. MR. MASSIE: So there were a number or a handful of other routes we did consider, but this chosen one was given -- was made just really on the access for -- that we'll have available to that cable going forward.

Q. And thank you, sir.

I think the first alternative to replace it as was -- definitely was in the business case, but the additional information about the other alternate route is helpful. 11:50

On the first day of the hearing in response to Mr. Marriott there was an exchange on whether capital additions for the streetlight conversion project would be a customer cost or a system cost. I think that was with you, Mr. Tenney, if you recall that.

The Board was wondering if this is going to be a system cost, could ATCO Electric Yukon undertake to provide the Board with a table showing the historical cost and accumulated depreciation and the resulting net book value that would be expected to be recovered for this project? 11:50

A. MR. TENNEY: Yes. We will undertake to do that.

Q. Thank you, Mr. Tenney.

UNDERTAKING - TO PROVIDE THE BOARD WITH A TABLE SHOWING THE HISTORICAL COST AND ACCUMULATED DEPRECIATION AND THE RESULTING NET BOOK VALUE THAT WOULD BE EXPECTED TO BE RECOVERED FOR THE CAPITAL ADDITIONS FOR THE STREETLIGHT CONVERSION PROJECT

Q. MS. SABO: I'd like now to move to one of the schedules. Actually, it's Attachment 9.2. So it's Exhibit BB-1. It's the YECL GRA application, Attachment 9.2, which is the 2017 capital expenditure information and page 2 of the hard copy. Page 189 pdf. 11:51

A. MR. MASSIE: That's the second page of generation appropriation is what I have. Is that correct?

Q. I've got it at the top. It's actually PLC replacement Stage 1, so it's Attachment 9.2, page 2.

A. MR. MASSIE: Sure, if you -- yeah, I think I'm there, if you just give me the -- oh, there. Okay. I went to the schedule. I am there. 11:52

Q. Thank you. I'm first of all going to look at the Teslin plant assessment where it says: (as read)

"The existing generating unit is contained in a trailered building on a

concrete foundation. During inspections, it was noted that there is considerable difference in elevation throughout the plant floor. The assessment will identify foundation and/or building deficiencies."

Our question is, since the problem in the floor and elevation been identified, could ATCO Electric Yukon go straight to bids from contractors to assess and fix the elevation problem versus doing an assessment? 11:53

A. MR. MASSIE: Yes, I think that is a possibility, be able to let them in there and assess the issue, I guess, and give us their recommendations to fix, and costs to fix, I suppose.

Q. Okay. And, Mr. Massie, would you expect that to be of similar cost to the 102,000, or would that reduce the costs required to fix this problem if you did it through bids rather than an assessment first?

A. MR. MASSIE: Sorry, can you repeat that?

Q. I'm just wondering if it's more cost effective to go straight to the bid tender process to look at getting it fixed rather than having an assessment cost included in your forecast. 11:54

A. MR. MASSIE: Mm-hmm. So I think one of the things we don't clearly detail in there is, you know,

the assessment is also going to give us an assessment of that -- of the plant overall health of the actual structure. But I don't think I would -- I would disagree. There's -- when we put it out for tender and for bid to fix it, there's just a few unknowns that we would -- we don't fully understand that could -- that I could give you any more detail, that the 102 could be high or lower than that.

Q. Thank you, Mr. Massie.

As an aside, I guess, with respect to capital projects ATCO Electric Yukon conducts, have you ever considered disclosing the results of bid tenders as part of a prudency review of the cost of the project? Now, I understand some of that information may be confidential, but to give you an example: In other jurisdictions, sometimes you'll see, you know, the ranking system, the final bids, maybe redacted copies of the bid tenders. Can you just give me a sense of -- of whether you've ever provided that information or would be willing to in the future? 11:55 11:56

A. MR. MASSIE: I don't know that we've provided that information in the past. You know, as we looked at the questions that we had on these projects and the variances and we went back and looked at the competitive processes that we put in place, I can tell

you we do have a very similar process in our tendering of our packages. There is a weighted score for each, you know, weighting of cost on the experience of the contractor, the references, timelines that they can meet. We do do all that in -- for our competitively tendered project.

A. MR. GRATTAN: And I'll just add to what Mr. Massie said is, is that there's a lot of what I would refer to as normal bread-and-butter-type utility construction work we do here in the Yukon. 11:57

In the past, where we do have something very unique -- and that was actually part of the 2008-2009 GRA where we were assessing moving to the next generation of billing systems, we went from an old billing engine to a more updated billing engine. And we did, as part of that proceeding, provide significant documentation on the record that evaluate the ratings and the rankings and the weightings of the various billing engine service providers that were out there.

So, in unique circumstances, we certainly have 11:58 done that in the past. When it comes to normal -- normal routine stuff, as Mr. Massie has pointed out, I would say we have not.

Q. Okay. And certainly if the Board were to request that information for projects, ATCO Electric Yukon could

provide some information at that time?

A. MR. GRATTAN: It is -- it is fair that the Board certainly can request that, and we would be certainly fine to provide in a way that maintains confidentiality.

Q. Okay. Thank you, Mr. Grattan.

Thank you for that foray. I'm going to take you back to Attachment 9.2 again looking at the PLC replacement, Stage 1. And we'd just like some more detail on what ATCO Electric Yukon is proposing to do with the $103,000 amount reflected there. 11:59

A. MR. MASSIE: Sure. So this PLC replacement, I guess it's important to note that there's two vintages as of now, two vintages of PLCs, control systems, that we utilize in our plants.

The ones that we've changed in Beaver Creek and Destruction Bay, they were -- I believe it's called an IDEC PLC. It was from a 1980s vintage, so there's that set of PLCs that we have out there. Then we have this newer -- as in from the '90s -- PLC system from GE. 12:00 **The difference and the benefit of the newer technology is that there is -- there is the ability to update and change these PLCs with the new upgraded hardware for the PLCs.**

It's not as in-depth as the older versions, the

IDEC versions, where basically all the hardware material, the whole system had to be decommissioned and removed and installed. This is more of a stepped process. It's my understanding that the majority of the hardware material that is out there in these PLCs will remain. It's more of electronics upgrades and a few small material items that need to be upgraded to -- to this PLC system.

So the Stage 1, really, we're looking at two -- two to three plants to go in there and put the -- 12:01
install or look at the existing system, understand what it's going to take to replace it. Install possibly, if we can, the first stage of it. And that would really show us what we need to -- what we need to inform our future stages and future PLC replacements. We'll be able to understand fully the ramifications of changing out these older ones with the newer ones and apply that to our future PLCs.

Q. Okay. So there could be several stages depending on the results of the success per PLC replacement here? 12:02
In Stage 1?

A. MR. MASSIE: Yeah. I would say this is -- this is Stage 1. I don't know if there's going to be several. But there definitely will be later stages to replace our PLCs to bring them up to a more modern

control system that can fully communicate with our SCADA systems and provide us some better data.

Q. Okay. And in terms of the Teslin plant assessment of 102,000, which we were discussing earlier, is that amount related to design only, or is it more encompassing to other items?

A. MR. MASSIE: No. It's not design only. And, I guess, I wasn't very clear there, and neither is the description. We based that amount on a past estimate we had for a new concrete pad in -- underneath this trailered unit. 12:03

Subsequent to that, it was thought that the actual trailer is what's the deficiency and not the concrete pad. So we've factored in some work on the concrete, but to look at the whole setup as a whole, the trailered unit and the concrete, to ensure that we get whichever deficiency -- whichever item is deficient fixed.

Q. And do you have the design for that project, how that's going to layout at this time, or is that still to be determined? 12:03

A. MR. MASSIE: Yeah. It's still to be determined. There's no finalized design yet or assessment.

Q. Okay. And the next item on there is the Watson Lake

plant fire alarm system for 102,000. Just had a question on whether there are fire alarm systems in other existing plants, or is this a unique item?

A. MR. MASSIE: Sorry. The question, are there any other fire systems --

Q. Alarm systems --

A. MR. MARTINO: -- in the plant?

Q. In your system. Like, are there other plants that ATCO Electric Yukon -- you have fire alarm systems for other plants in that -- not just Watson Lake? 12:04

A. MR. MASSIE: Yeah. Yeah. There would be an updated one in the new Old Crow plant. The older plant would have very basic ones, fire detection systems. This is really looking at -- there is a new design or new systems out there where the -- in the case of Watson Lake, if you look at the fire alarm system, instead of just heat and smoke detectors, as it mentions there, it will have individual sensors for each unit. So it will understand -- if the fire is contained to one unit, it will be able to shut off the 12:05 **fuel just to that unit.**

Then there's the -- the other systems will detect if it's a bit bigger and if the fuel system needs to be shut off for the whole plant or just one specific unit.

So, yeah, it's -- the system that we're looking at

here, and it's not -- again, we're just looking at the design of them, because there's a whole host of options that can be looked at for the system; but, as that system I just described, that isn't -- we don't have that system in place anywhere.

Q. Okay. So we don't know the expected total cost for that system as of yet? This is just the design cost?

A. MR. MASSIE: Yes. Again, there's a number of options, as we understand it, that there could be put in place for that power plant. We're going to look at the design. That will give us some informed costs for each one of those options. So we'll understand if -- be able to weigh the benefits of a better option or adding more options or not. 12:06

Q. Okay. Thank you, Mr. Massie.

MS. SABO: Mr. Chairman, I just have one more project to question on. I know we're a little bit over lunch, but I would appreciate your indulgence, if we could just finish off capital.

THE CHAIR: That's fine with everyone else, we'll just carry on. 12:06

MS. SABO: Thank you.

Q. Mr. Massie, I don't really want to pull up too many references here, but we just want to understand in terms of PLC controller upgrades, you've done one at

Destruction Bay for $307,000, and then we have the Beaver Creek programmable logic control PLC upgrade.

And just in terms of costing and lessons learned, we were -- we were wondering with respect to the Beaver Creek PLC controller upgrade project, did you apply any of the knowledge or the learnings from your Destruction Bay project to Beaver Creek? Or are they just -- you didn't -- they're not interrelatable? There was no sort of nexus between what occurred at both of those areas? 12:07

A. MR. MASSIE: No. It's a very fair question. Just -- the DB -- D Bay PLC project is forecast for 2017 for that -- the 307. We have incurred costs in '14 and '15.

But they are similar very similar systems for the Beaver Creek and Destruction Bay power plants.

We've looked at our project that we completed in Beaver Creek; and, really, the lessons learned -- again, we really underestimated the issues we were going to have in decommissioning the old PLC as we 12:08 **installed the new PLC while keeping the community's power on.**

As well as we ran into an issue in particular to that power plant that the Beaver Creek 2 replacement project was delayed, and it wasn't completed in '13.

So that -- we were expecting the new unit to show up already with that PLC system attached to it. So we wouldn't have to worry about that.

So there was definitely, as you say, some lessons to be learned from that one. They have been fully incorporated into our forecast for Destruction Bay. And I think that's why we see that number adjusted to 307 in 2017 compared to -- and, again, we already have -- and I think it's 109,000 in costs for that project. 12:09

But it's -- we've definitely informed ourselves and looked at that project in Beaver Creek, very similar one to D Bay, and what we'll need to complete that project incorporated in that forecast.

Q. And I don't have the numbers in front of me, Mr. Massie, but in terms of magnitude between those projects, is Beaver Creek a lot bigger or a lot smaller than the DB controller upgrade? Can you just give me a ratio show or a sense of the magnitude?

A. MR. MASSIE: Again, they're very similar power plants. They're three-engine power plants. You know, they have this -- that -- that similar PLC that needs to be replaced. 12:10

The difference I see for Destruction Bay is that we have two newer units in there that have been

recently replaced in '14 and in '15, with D Bay 2 being finished in '16. They would already have that updated PLC attached to that unit, and it would be -- right now, as it's running, it will be able to communicate with the old PLC of the power plant.

So each unit has its own separate controller, and then the power plant also has its central controller which controls, you know, the coordination of putting that generation onto the grid, the fuel system, and the -- a host of other power plant -- common power plant controls. That's what it does. 12:11

So very similar projects, very similar power plants, both in vintage and the setup of their units.

Q. Thank you, Mr. Massie. Those are my questions on capital.

MS. SABO: Mr. Chair?

THE CHAIR: All right. Does any Board member have any questions for the panel?

MS. SABO: Just lunch break we thought first.

THE CHAIR: Oh, just lunch break. Okay. No, 12:11
I thought you were saying --

MS. SABO: I still have a few more questions.

THE CHAIR: Okay. I wasn't sure about that, obviously. All right.

So it's 10 after 12, so why don't we convene at

20 minutes to 2, 90 minutes from now. Is that right?

A. MR. GRATTAN: Unless we were to go less than an hour. Subject to --

THE CHAIR: We can do that too. I'm --

MS. SABO: I know --

THE CHAIR: What works?

MS. SABO: Yeah, that's fine. I just note that a majority of the intervener groups had a lunch-hour conference, and they'll be back at 1:30, so I'm fine to keep -- 12:12

THE CHAIR: Well, let's go to 1:30 then. That weeks for everyone?

MS. SABO: Yes.

THE CHAIR: All right.

MS. SABO: Thank you.

(PROCEEDINGS ADJOURNED AT 12:12 P.M.)

PROCEEDINGS ADJOURNED TO 1:30 P.M.

Volume 3
November 3, 2016
P.M. Session

(PROCEEDINGS COMMENCED AT 1:32 P.M.)

UNDERTAKING RESPONSES:

THE CHAIR: Thank you, everyone.

So, Mr. Williams?

MR. WILLIAMS: Yes, sir. We have -- in order to be -- to be as efficient as possible here, we're going to try to respond to some of the undertakings from this morning just orally. The panel is prepared to deliver some of those answers. So if that's okay with the Panel and Board counsel, then we'll proceed in that manner. 13:33

MS. SABO: No objections from Board counsel.

THE CHAIR: Go ahead.

MR. WILLIAMS: Thank you, sir.

I'm going to turn things over to Mr. Grattan first, and he's going to respond to what I believe were the first and second undertakings taken this morning. He's also going to respond to one of his subject to check -- or his subject to check. So he'll be responding on three matters in total, sir. And then we'll turn things over to Mr. Massie, who will respond 13:33

to I believe what amounted to the fourth undertaking from this morning.

THE CHAIR: Go ahead.

A. MR. GRATTAN: Okay. So I'm going to hopefully clarify the discussion that was going on this morning about the amortization period of Demand Site Management costs. And we were trying to confirm where the five-year amortization period came, or the 20 percent amortization rate that's detailed on Schedule 7.3. And that comes from Board Order 2014-06, page 101, or 101, 13:34 **where the Board stated the Board orders that Yukon Electrical that capital the amounts of DSM spend in '2011, '12, and '13 relating to the development of the plan or policy paper and the pro rata amount of the costs already spent in 2011, '12, and '13 but not related to the development of the plan or policy paper and to amortize these costs over the 2014 to 2018 period.**

So that was -- that was what informed us as to amortize things as part of the 2014-06 decision. And 13:35 **we have used that same precedent for purposes of amortizing the DSM costs that were incurred in the years '14, '15, and '16 over a five-year period beginning in 2017. So I think if I've explained that correctly, we should be exactly the same as to how it**

was treated last time versus what we're proposing to treat it this time.

So that covers, I think, the two undertakings.

The subject to check, we were discussing the Watson Lake bi-fuel project and the addition of Watson Lake bi-fuel capital into Schedule 7.3. And I think the Board was asking for me to confirm that the Watson Lake bi-fuel was being added into Account 445, generating equipment and prime mover other.

And, yes, as I said, that was going to be the largest account that was used for purposes of the bi-fuel project. But there are also small amounts of Watson Lake bi-fuel that go into Account 444, which is fuel holders, producers, and accessory equipment; as well as Account 446, which is accessory, electrical equipment, other. 13:36

So between those three accounts, that's where the Watson bi-fuel capital is going. And as agreed by myself earlier, the majority of it goes into 445.

MS. SABO: Thank you, Mr. Grattan. If Board staff has any questions, we'll follow up with you in writing. 13:37

MR. WILLIAMS: Mr. Massie, we'll turn things over to you, sir.

A. MR. MASSIE: Yes. I was to provide the

year-to-date costs for new extensions, and as of October 31st, 2016, our actual costs are $2,116,000.

MS. SABO: Thank you, Mr. Massie.

MR. WILLIAMS: With that, Mr. Chairman, I believe we're done with what we're able to provide at this point in time.

THE CHAIR: Okay. Thank you.

Ms. Sabo.

MS. SABO: Thank you, Mr. Chairman.

Q. I do have a few follow-ups from this morning on capital. 13:38

Mr. Massie, you were talking about PLCs and DL -- diesel generation unit this is morning, and I have a high-level question. Generally, when you install a new diesel generation unit, would new PLCs come with the unit, or would you use existing PLC?

A. MR. MASSIE: A new -- a new unit would come with a new PLC already attached, yes.

Q. Okay.

A. MR. MASSIE: To be certain, there would be modifications that will need to ensure that it works. If we're putting it into an older plant that has an older PLC, there will be some modifications we will need to do, but the unit does come with an updated PLC. 13:39

Q. Okay. Thank you. I would like to take you back. We

were talking a little bit about manufacturing of generation and diesel engine units and warranties in terms of Watson Lake, and the Board has a few follow-ups. Is the manufacturer of the conversion kits for biofuel generation the same as the manufacturer of the generation engine? Do they come from the same manufacturer?

A. **MR. MASSIE: Well, we are planning on competitively tendering the process. The manufacturer of the units does provide the bi-fuel kits, so we are assuming that they will be responding to that tender.** 13:40

Q. So it's uncertain at this time whether they will be the same as the manufacturer of the diesel generation units.

A. **MR. MASSIE: That's a fair assumption. It could be -- they could be, or it could be another third-party, yes.**

Q. Okay. For example, for the diesel generation Unit Number 2 that you're replacing, what is the warranty for that unit? 13:40

A. **MR. MASSIE: And to be specific, I would have to undertake to provide that, but generally the diesel units come with warranties of a certain time, whether it be six months or 12 months and operating hours. So usually there is one or the other that will have a**

warranty unit -- a warranty timeframe for the unit.

Q. Okay.

A. MR. MASSIE: Could be a combination of the both or one or the other.

Q. Okay. And would that warranty be impacted by the addition of the conversion unit that you would be placing on these diesel generators?

A. MR. MASSIE: Again, we -- we're not expecting it to be impacted, but that would have to be determined at the time of the successful tender process, I suppose. 13:41

Q. And that would apply to both of the warranties you mentioned; right? You're uncertain on both the operating and the other warranty, how that would be impacted?

A. MR. MASSIE: Sorry. The -- the two warranties?

Q. Yeah. I'm just trying to make sure that we're talking about, if the warranty is impacted by the conversion unit, you mentioned two different types of warranties. So... 13:42

A. MR. MASSIE: Oh, sorry. Yeah. It's the same warranty. It's just the hours -- there's an hours demarcation, operating hours for the unit that's covered by warranty or time, whichever comes first. So it's not operating very much in the first 12 months,

then if it was a 12-month warranty, they would go with the 12 months.

Q. Okay. Thank you for that.

I would like to ask a question on cost of debt, and it's in the IR responses at Exhibit B-9, and it's the YUB-YECL-73.

A. MR. GRATTAN: Just one moment, please.

Q. No problem. And I've got a pdf page of 398, Mr. Grattan. So I don't know if that's close to where you need to be. 13:43

A. MR. GRATTAN: I'm there.

Q. Thank you.

And I've glad you got a hard copy, because we put together our compilation tables of the bond rates. So I'm going to walk through.

2011 bond spread, the 2011 actual we have at 1.637 from that IR. And it might be in (b) or (c).

A. MR. GRATTAN: Yes, I see it, yes.

Q. Or (a).

And 2012 actual is 1.533? 13:44

A. MR. GRATTAN: Yes.

Q. 2013 actual is 1.589?

A. MR. GRATTAN: Yes.

Q. 2014 actual, 1.475?

A. MR. GRATTAN: Yes.

Q. 2015 actual, 1.767?
A. MR. GRATTAN: Yes.
Q. And then 2016 forecast and '17 forecasts we have at 1.8.
A. MR. GRATTAN: Correct.
Q. Great. And we're just wondering, given that trend between the actuals and the forecasts, can you explain the trend in the actuals, why that change had occurred, that upward trend in '15?
A. MR. GRATTAN: No. I won't -- I'm not going to be able to explain it at any technical level, other than I can share that in the recent Alberta generic cost of capital decision, I have read that the Alberta Utilities Commission has noted recent spreads increasing. So that it was -- it was noted by the Alberta Utilities Commission. I presume it was also noted by the various parties in -- as part of the Alberta GCOC. 13:44
Q. Okay.
A. MR. GRATTAN: That's about all I can say about it. 13:45
Q. That's fine. Yeah. We were just noting that the variation in numbers, you know, it seems to be higher in '11, '12, '13 actual, and then you have a dip in '14, and then back up in '15.

So can you explain why the forecast years show a higher bond spread than those historicals? Why are you forecasting --

A. MR. GRATTAN: Sure. Well, the -- I think what our treasury department has based this forecast on is recent spreads, as is noted in this -- as is noted in 2015, the spread increased between '14 and '15 to a point of 1.67 -- 1.767 in 2015. And the treasury department has taken it up to 1.8 for forecast purposes for each of 2016 and '17. So I'm not sure I can add much more to it other than it's based on recent bond spreads. 13:46

Q. Okay. Thank you.

I have some questions about the deferral accounts applied for, and you provided a summary table in response to -- I believe, it was YEC, and it's the last page of their IRs at Exhibit B-8, pdf page 40 of 40.

A. MR. GRATTAN: Sorry. Can you repeat which YEC response, please?

Q. Yes, I can. Move some notes around, Mr. Grattan. So I'm going to find it again here. It's YEC-16. 13:47

A. MR. GRATTAN: Thank you.

Q. And the very last page of those IRs.

A. MR. GRATTAN: I am there.

Q. Great. Thank you.

As you well know, there's a -- reflected in that table, there's a diesel fuel deferral account that's been previously approved by the Board. And we just wanted confirmation if the account -- only accounts for changes in the price of diesel, or is there more included in that account?

A. MR. GRATTAN: The -- it is a status quo. So the diesel fuel deferral account is strictly dealing with price variances tied to diesel fuel.

Q. Okay. 13:48

A. MR. GRATTAN: And then -- presumably you're going to go on to the next line, LNG fuel deferral account.

Q. Yeah. Again, yet does that only account for change in prices?

A. MR. GRATTAN: Yes. So it's just a different fuel. And we're certainly open to how the Board -- if the Board believes there's a better way of handling this, we're open; but our proposal is to have two separate deferral accounts, one for diesel fuel, and one for LNG fuel. 13:48

Q. Thanks for getting ahead of me, Mr. Grattan.

The other -- I know we did recently for ATCO Pipelines in Alberta, we had one deferral account, but we had them account different types. So LNG, say,

in one line item and diesel fuel in the other, and then one account. So you wouldn't object to anything like that?

A. MR. GRATTAN: We would not.

Q. Thank you.

And moving back up to the purchase power flow-through, I want to take you to a different IR. It's a Commission IR, YUB-YECL-47(b).

A. MR. GRATTAN: Just one moment, please.

Q. That's fine. And it's hard copy page 3. 13:49

A. MR. GRATTAN: I am there.

Q. Thank you.

In that response, ATCO Electric was asked to comment on whether under a power purchase flow-through deferral account, it would be guaranteed a fixed margin, where the fixed margin was defined as incremental sales revenue less power purchase costs, as set out in the last GRA. And ATCO responded in part that it would assume risk associated with sales volume but would not assume risk associated with changes to 13:50 the wholesale purchase rate.

Can you explain what is meant by a "sales volume risk" in that context?

A. MR. GRATTAN: Sure. So as part of -- as part of this application, we have had significant discussions

with respect to how ATCO Electric Yukon's actual sales have turned out compared to what was awarded or approved. And over the last three years, for example, we have had actual sales come in lower than approved, and that has resulted in us having a lower margin, which is the delta between what was forecast for sales less us buying less electricity from Yukon Energy. So from a pure volume perspective, we have either a risk that we are going to have less margin, or we're going to -- if actual sales come in higher, we're going to have more margin. It's not much more complicated than that. 13:51

Q. Okay. And I'm sure the parties may to want to reply on this in argument and reply argument, but I would like some follow-up for you whether -- does that -- does it mean that there would be a guaranteed fixed margin on sales in excess of forecasts through the use of the power purchase flow-through deferral account as proposed by ATCO Electric Yukon?

A. MR. GRATTAN: I think you're going to -- I better let you repeat that, make sure that I got -- 13:52

Q. Okay.

A. MR. GRATTAN: I got it. A guarantee fixed margin.

Q. On sales in excess of forecast.

A. MR. GRATTAN: So if -- maybe the easiest way to explain this would be to use a simple example.
Q. Great.
A. MR. GRATTAN: And -- let's see here. How can I go about this? Okay. So there's -- the current Block 1 energy rate, excluding riders for residential, customers is 12 cents. So if our actual sales are 1 kilowatt hour higher than what was forecast, we're going to have an additional 12 cents. And because we're buying in the hydro zone, our electricity from 13:53
Yukon Energy at -- is that 8.3 cents -- 8.3 cents, we're going to have to buy -- I'll just round it to 8 cents so I can get my math right here.

If we're -- given that we're going to have one additional kilowatt hour of sales to factor in line losses, which is at 6 percent or about that, we're going to have an additional 8 cents of purchase power cost. So the delta between those two at a real simplistic level is 4 cents. So our gross margin will go up 4 cents if we have an additional kilowatt hour of 13:54
sales higher than forecast.

Vice versa, it goes in the other direction if we are -- if our sales forecast is too high, which has been the case the last number of years.
Q. Okay.

A. MR. GRATTAN: Is that helpful?

Q. Thank you, Mr. Grattan.

A. MR. GRATTAN: And just one other thing. Mr. Tenney is also reminding me, and it's just to add a little more complexity to the equation here.

We also -- that's -- that 12 cents was based on the first block of rates. We also have a block between 1,000 and 2,500 kilowatt hours and over 2,500 kilowatt hour. And each one of those blocks has different rates. For example, the second block has a rate of 13:55
12.8 cents, and the third block has a rate of 13.99 cents. So depending on what goes on between actual and forecast, you could have margins bouncing around, either us having additional earnings or net earnings, net margin, or additional loss of margin.

Q. Okay. So by having that deferral account in place, does that result in a guaranteed fixed margin for ATCO Electric Yukon on sales in excess of the forecast?

A. MR. GRATTAN: I think it guarantees that there will be -- there will be an additional margin, whatever 13:56
it turns out to be, if sales are higher than forecast. And then I keep repeating. It's the same deal on the other side, so it's mirrored one way or the other.

Q. Okay. Thank you. I would like to move on to the pensions deferral account, and I just wanted -- I

understand that -- the matters before the Alberta Utilities Commission on the pensions for 2014 and '16. But are there any unique or special charges that may apply to ATCO Electric Yukon that would not apply to the other ATCO entities that we should consider in terms of pensions and pension deferrals?

A. MR. GRATTAN: If there are any, I am not aware of them.

Q. And given that proceeding is a 2014 to 2016 proceeding, how would you expect to adjust for the pension amount for '16 and '17 in this proceeding -- 13:57

A. MR. GRATTAN: So --

Q. -- or after?

A. MR. GRATTAN: Sure.

Q. Yes.

A. MR. GRATTAN: The pension application currently before the Alberta Utilities Commission covers the period '14, '15, and '16, and for the period 2016, ATCO -- the ATCO Utilities have requested the COLA to be 100 percent, as opposed to do the currently approved level of 50 percent. 13:58

For 2015, I believe they've -- ATCO Utilities has asked for 80 percent of COLA as opposed to the currently approved 50 percent. So I'm anticipating, if the world unfolds as we anticipate it, that the

Alberta Utilities Commission will either -- well, it's going to land on a number of possibilities, but we fully anticipate for 2016 forward whatever the Alberta Utilities lands on, that's what we will incorporate for our proposal in this application.

Q. Okay. Thank you, Mr. Grattan. I think the Alberta Utilities Commission is probably glad you didn't reference any numbers there, since I'm counsel on that proceeding.

For ATCO Electric Yukon's DB pension for placeholder amounts for the test years, do the amounts contain any provisions for special payments? 13:58

A. MR. GRATTAN: They do not.

Q. Well, I --

A. MR. GRATTAN: Sorry, and just -- sorry. That -- that was updated. In the latest numbers that we've provided, that there is no special payment for 2016.

Q. Thank you for that additional response.

And special payments, that's '16 and '17; right?

A. MR. GRATTAN: Correct. Based on the actuarial evaluation as of December 31st, 2015, and that is the latest forecast. There would be no special payments for the years '16 or '17. 13:59

Q. Okay. Will ATCO Electric Yukon's defined benefit pension be considered to be in a liability position for

either of the test years?

Yeah, I think you answered that. I just wanted to confirm.

A. MR. GRATTAN: That I'm going to have to -- when you say a "liability," like, the overall plan?

Q. Yeah. I was thinking on the higher level, rather than on the special payments.

A. MR. GRATTAN: Just one moment. I'm not sure. I've got to be careful here because you've asked -- you think that I've answered it, but I'm not sure I have. I don't know whether you can help me where you think that I've answered it. 14:01

Q. Well, we were just talking about how the special payments are one issue and the overall liability of the fund is a different issue.

A. MR. GRATTAN: Yes.

Q. So if you have any comments on the overall liability, that's fine. If you don't, that's fine as well, Mr. Grattan.

A. MR. GRATTAN: Okay. If you'll let me off the hook on that one, I would prefer not to speak to the overall plan. 14:01

Q. Yes. Thank you.

ATCO Electric Yukon is asking for a deferral account for regulatory changes and load changes due to

government programs, which has been discussed in previous days of this hearing.

The Board would like more detail on how this deferral account would work.

A. MR. TENNEY: So there is a response that I'm sure you're aware of, YUB-2(b).

Q. Yes.

A. MR. TENNEY: So it's my understanding that the one example that I'll use is the IPP policy that we talked about on Day 1 of the proceeding, where, if the government ends up with a policy that we have to purchase power from an IPP that's greater than what the costs would have been had we generated the power ourselves and if the government doesn't backstop that situation, we would propose to put that in a deferral account and come back before this Board in a subsequent GRA to look for collection if those costs are prudent.

14:03

Q. Okay. So would it be fair to say, Mr. Tenney, that the parameters for what you're expecting in this account would be sort of any sort of government policy? As it kind of arises within the test period, then you would put in those amounts, and then it would be up to the Board to determine whether those amounts were prudent after they were incurred?

14:03

A. MR. TENNEY: That would be how I would think it

would work.

Q. Okay. Thank you.

I have a few questions on errors and omissions, which is my final area. We notice that you put on -- and it's well-established on the record -- you put in an update of October 24th on errors and omissions that you corrected as of that date. We were just wondering, are there any other error and omissions that you're aware of as of today?

A. MR. GRATTAN: From a revenue-requirement perspective, we're not aware of any other changes. The only reason I was having this conversation is, is that one of the tables that was being referenced to yesterday, I believe -- it's an O&M table that determines O&M per customer, I believe. 14:05

Q. Yes.

A. MR. GRATTAN: There's a mathematical error on it that we are wanting to correct. We were going to put that in along with our remaining undertakings. And it's just a mathematical error in that table. 14:05

Q. Okay.

A. MR. GRATTAN: So that's -- it's something that we would just make sure that the record is as clear as possible.

Q. That would be appreciated, Mr. Grattan. I'll leave you

with that.

We also do have one that we noticed as well. It's not necessarily an error and omission, but in the October 24th, 2016, update, and it's -- for the Board's reference, it's Exhibit B-13.

And I'm going to take you to line 1 of Schedule 10.1, which is the utility EBT.

A. MR. GRATTAN: Just one moment, please. I'm there.

Q. Okay. And I've got a note here, the correction of that error resulted in an EBT for 2016 changing the amount from 3.2 million to 3.944 million, which is an increase of 661,000. And then for 2017, the resulting change for EBT was from 4.542 to 3.728, which was a decrease of 814. 14:07

Are you seeing that there, Mr. Grattan?

A. MR. GRATTAN: So I'm not sure I heard you correctly. It's my understanding that for 2016, the original schedules --

Q. Yes. 14:08

A. MR. GRATTAN: -- showed a utility earnings per tax -- or utility earnings before tax of 3,944,000, which was decreased to 3283.

Q. Okay. I think we have that backwards.

A. MR. GRATTAN: Yeah. And then for 2017, it was

originally stated that 3,728,000 and updated to 4,542,000.

Q. Okay. Thank you, Mr. Grattan. And just -- we noticed in our Excel versions of Schedule 10.2 there was no formula in the cells --

MR. GRATTAN: Yeah.

Q. -- for the test years.

A. MR. GRATTAN: Yes.

Q. Are you able to provide us an Excel version of the schedule with working formulas? 14:09

A. MR. GRATTAN: Of course.

Q. Thank you. And that --

A. MR. GRATTAN: I can undertake to do that.

Q. That is your final undertaking from me today, sir.

UNDERTAKING - TO PROVIDE AN EXCEL VERSION OF THE SCHEDULE 10.2 WITH WORKING FORMULAS

MS. SABO: Thank you, panel. We really appreciate you attending today, and we know it's been some long days, and we appreciate your responses. 14:09

A. MR. GRATTAN: Thank you.

A. MR. MASSIE: Thank you.

THE CHAIR: Thank you.

Did any Board members have any questions?

THE CHAIR QUESTIONS THE PANEL:

Q. So I had one. And yesterday I think it was Mr. Tenney was having a discussion with Mr. Rondeau from UCG, and it was talking about consultations with the public and those sorts of things. And I note that YCL or AEY was in attendance at the recent LNG facility proceeding that the Board conducted. And I'm not sure if any of you attended the -- there was an evening session that the Board scheduled there in which the public had an opportunity to address the Board. 14:10

These proceedings are necessarily formal and often intimidating and aren't really a very good vehicle for people to do that. And -- but you had indicated some thoughts about the Board doing things like that. And I wondered if you had any comments on the -- on any benefit that you may have seen coming from that. I mean, recognizing that the Board is an evidentiary-based thing, and panels come and provide evidence, which is tested, and that kind of material is not. But do you think it informs the process in any way? 14:10

A. MR. TENNEY: So I wasn't at that myself. I don't know if my colleagues were. But I would suggest anything that allows the public to participate -- I would think if I was coming into this room to make a

presentation, it looks rather intimidating, and I can't even keep up with the volume of data that's in here. So it's a difficult task.

So if there's a more informal way to engage our customers about what we're doing, I don't think we would be opposed to any of that. But it's hard sometimes to translate what they exactly say to us and whether we actually took action or whether they perceive that we took any action that could be a challenge. But we're open to any of those forums. 14:11

As -- as Mr. Rondeau suggested, it's probably unlikely that a lot of our customers are looking in the newspaper to see that we're planning a rate application, and then whether they would attend an event like this.

So we're open to it. We don't have any earth-shattering suggestions here about what that could look like and how it would be benefit -- or how you could structure it to make sure it was most beneficial. But we're open to that. 14:12

Q. Yes. It's not likely -- the general public doesn't always read the legal notices in the paper, and so -- but I'm wondering how you think, maybe, that those sorts of comments that come to people if, say, at that event we scheduled, I don't know, two or three hours

and gave people five minutes or whatever, and they had to register in advance, but really the information that they gave was only of value to interveners or panelists who might incorporate that into what they were doing. It's not something that really can enter into the Board's deliberations. So I wonder if you see a way to get that information and use it with the public?

A. MR. TENNEY: So if I understood you -- and again, I apologize that I'm not familiar with what happened in that evening event at the LNG facility proceeding, but if you're suggesting customers, residents in the Yukon can attend an informal session with intervener groups, and intervener groups can utilize those thinking into the process, that's your question: Would that be beneficial? 14:12

Q. Yes.

A. MR. TENNEY: Well, I think it is, but if somehow it would be -- there's a part of me -- and I know we always like to think we're going to do a great job educating staff but -- or our customers, I'm not sure most customers understand how we go about -- all of us go about setting rates, what makes up revenue requirement after you get revenue requirement, how does it get allocated to customer class, and then how do you ultimately design rates. 14:13

That's probably the biggest barrier to everybody participating fully is they don't quite understand how all that works. So we'd love to say, well, let's just educate them, but how do you get them to come out to get educated? And it might not be -- surprise to some of us, but it might not be the most exciting subject matter.

So I'm not sure -- again, I'm not sure I'm giving you anything, but the more we can do, the better off we're going to be, because if we don't have public participation in front of the Yukon Utilities Board, we don't really have a great rate-setting mechanism. 14:14

Q. Okay. Thank you for that. And at that event, of course, we recorded that stuff. It formed part of the transcript, although it didn't really enter into the decisions. But if people took some of those concerns and incorporated them into their questions or their answers, that would be useful.

Okay. Thank you for that. And that's all that I have. 14:14

THE CHAIR: Anybody else? No.

Then subject to the panel finishing up with the odd little undertaking or subject to check that they need to report on, I think that we can release this panel.

MR. WILLIAMS: Yes, sir. I just have a couple -- couple hours of redirect maybe.
THE CHAIR: Okay. Only two? Sorry, I forgot to ask you about that.
MR. WILLIAMS: No, I'm good, sir. We can release this panel.
THE CHAIR: You don't have anything for them?
MR. WILLIAMS: No.
THE CHAIR: Okay. So, panel, thank you for your time and your patience. 14:15
A. MR. TENNEY: Thank you very much.
THE CHAIR: And Godspeed.
A. MR. MASSIE: Thank you.
(PANEL STANDS DOWN)
MS. SABO: Do we want to maybe take a ten-minute break to switch out the panels?
THE CHAIR: Okay. We'll do that so that the panel can pack themselves up, and then we'll put the other panel on. So where are we at here? So say 25 past we'll reconvene. Thank you. 14:15
(ADJOURNMENT)
THE CHAIR: So good afternoon again.
And are we ready to proceed with the City of Whitehorse panel, Mr. Marriott?
MR. MARRIOTT: Yes, sir, we are.

THE CHAIR: Would you like to introduce your panel.

MR. MARRIOTT: Good afternoon, Mr. Chairman, Board members. It's my pleasure at this time to introduce to you the witness for the City of Whitehorse. Mr. Russ Bell.

Mr. Bell prepared the evidence that is marked as Exhibit C3-3. And his responses to information requests from the Board are marked as Exhibit C3-4.

Mr. Bell is a chartered professional accountant. And his experience and training are outlined in Appendix A of his evidence. And with that, by way of brief introduction, I would ask that Mr. Bell be sworn, please. 14:39

R. BELL (For City of Whitehorse), sworn

MR. MARRIOTT EXAMINES THE WITNESS:

MR. MARRIOTT: Okay. Thank you.

Now, Mr. Chairman, what I propose is that I'm going to move to the formal introduction -- sorry -- formal adoption of evidence by Mr. Bell, and then I'll have him say a few things to the Board about his training and experience. 14:40

Q. So, Mr. Bell, a few moments ago I mentioned Exhibits C3-3 and C3-4. Were those documents prepared

by you or under your direction and control?
A. Yes, they were.
Q. Do you have any corrections to make to any of that material?
A. No, I do not.
Q. Are those Exhibits C3-3 and C3-4 true and accurate to the best of your knowledge and belief?
A. They are.
Q. Do you adopt those exhibits as your evidence on behalf of the City of Whitehorse in this proceeding? 14:41
A. I do.
Q. Now, Mr. Bell, as I mentioned, before I turn you over for questioning, I would ask that you outline for the Board's benefit your qualifications, training, and experience relevant to your testimony, and feel free, in doing so, to refer to Appendix A in Exhibit C3-3 as you do so, sir.
A. Thank you. I hold a Bachelor of Commerce agree from the University of Alberta. I received that in 1981. I'm also a professional accountant, a CPA, formerly a 14:41
CMA or certified management accountant. I have over 35 years' experience in the utility industry, starting my career at Canadian Western Natural Gas in Calgary, which is the local gas transmission and distribution company, as well as providing retail.

In that, I've done work in accounting, business planning, budgeting, rate applications, and in IT. I ended my career with ATCO as controller of their IT division, ATCO I-Tek.

Since leaving ATCO, I have been a consultant representing the interests of customers, largely working on a number of files for General Rate Applications, specialized applications regarding income tax, smart metering. As well, recently I've been involved heavily involved in the recent performance-based regulation initiatives in Alberta representing customer interests in the first and now second-generation PBR proceedings. 14:42

Q. Thank you, Mr. Bell.

MR. MARRIOTT: Mr. Chairman, Mr. Bell is available for questions.

THE CHAIR: Thank you.

So, Mr. Williams, YECL, will you be asking any questions?

MR. WILLIAMS: Sir, I would ask that you maybe canvas the other interveners first. I understand that one of them may have some questions, and if it would please you, I would like the opportunity to go last, if possible. 14:42

THE CHAIR: That's fine.

So UCG, Mr. Rondeau.

MR. RONDEAU CROSS-EXAMINES THE WITNESS:

Q. Good day, Mr. Bell.

A. Good afternoon, sir.

Q. My first question would be that you summarize a bit of the evidence that you've presented to us on the functional review of YECL's cost and showing that you believe there's a consistent pattern for YECL or AEY to overforecast its costs that are being used to establish rates. 14:44

THE CHAIR: Mr. Williams.

MR. WILLIAMS: Sir, this is -- Ms. Sabo and I discussed this briefly. I'm certainly happy to have interveners question Mr. Bell, but obviously there's a fine line between relevant questions from interveners and what would -- what I would term as sweetheart cross here. And I'm hesitant to give Mr. Bell another opportunity to elaborate on his evidence as a result of questions from Mr. Rondeau.

MR. RONDEAU: I'm simply asking for a summary. 14:44 Either way, it doesn't matter that much.

THE CHAIR: Why don't we try it this way: Do you have questions about some areas that he's asked, and would you like to --

MR. RONDEAU: I certainly do.

THE CHAIR: Okay. Would you -- why don't we try it that way.

Q. MR. RONDEAU: Is it fair to say, Mr. Bell, that based on your analysis, AEY's rates over the last several years have resulted in recoveries from ratepayers that are significantly -- significantly above the required levels?

THE CHAIR: Mr. Williams.

MR. WILLIAMS: Sir, I -- I'm not trying to be difficult, and I do hate to take this position at this point, but this is clearly sweetheart cross, and I need to object to it, sir. 14:45

MR. RONDEAU: I'm not trying to sweetheart cross, I'm just trying to get at the meat of the matter here.

THE CHAIR: Maybe you could rephrase that question in a way where you're asking him -- I'm not going to tell you how to ask the question, but I think there's another way to ask it.

MR. RONDEAU: Okay. 14:46

Q. Is it fair to say that, based on your analysis, that AEY's rates have been overforecasted?

MR. WILLIAMS: Sir, I'm not -- again, I'm not sure there is a way for him to ask this question that wouldn't amount to sweetheart cross. Either way,

Mr. Bell's evidence stands for itself.

I think the only -- the only party here that is adverse in interest in a strict legal sense to Mr. Bell would be YECL, so I think unless Mr. Rondeau has questions about Mr. Bell's experience or something like that, I'm not really sure where we can go with this line of questioning.

THE CHAIR: Well, Mr. Rondeau -- well, just let me hear from our counsel first.

MR. RONDEAU: Yes. 14:47

MS. SABO: Mr. Chairman, I just thought from -- I can give legal advice from legal counsel for the Board's perspective. And Mr. Williams is correct. I informed parties yesterday that, if they have a specific question on a specific portion of Mr. Bell's evidence, that they're all welcome to ask those questions. And certainly, as you have pointed out, the Board certainly doesn't want to direct the questions people ask; but if Mr. Rondeau is able to point to a certain portion of Mr. Bell's evidence or an IR 14:47 response in framing a question, that would probably be helpful without us foraying into sweetheart cross.

MR. MARRIOTT: Maybe a comment from me might be of some assistance. I would just say this from the City of Whitehorse's perspective: Mr. Bell's here to

answer any questions the Board considers relevant and appropriate. We're not here to do anything that would be contrary to practice or what has been built up as sort of the rules relating to this issue.

So, in Alberta, certainly where I do most of my work, there is a rule against sweetheart cross-examination, which essentially means a party essentially on the same side as Mr. Bell is using the examination to emphasize or reiterate a position that they already agree with. 14:48

Where I've seen other tribunals allow examination by an intervener that looks to be aligned in interest would be on true matters of clarification where something was unclear, and they're trying to elicit clarity.

MR. RONDEAU: I think I understand that.

THE CHAIR: Okay. Thank you for that. I just need a second, please.

Yes. So I think Mr. Bell's evidence is on the record, and it's been accessible to everyone. So if 14:49 you have a question about a specific conclusion or about how he arrived at that conclusion that you could ask him or that you wanted to shed some light on, that I think would be an appropriate area. But these other kinds of questions I think are not.

Proceed.

MR. RONDEAU: I'll try this one, and we'll see where it goes.

Q. Do you have any recommendations on how applications by the Yukon utilities could be improved to present a more useful picture of past performances versus the test year forecast?

A. In my evidence, I have done an analysis that is not different than I have done in other jurisdictions where I've compared forecast accuracy over a recent historical period to assess whether the utility has a history of overforecasting or underforecasting in a specific area. 14:50

In my analysis, I have derived the results I have in my evidence based on that experience and that practice.

In terms of how a utility could improve its forecasting, I think it's up to the utility to develop a forecasting methodology that it thinks is reasonable and produce evidence that it asserts supports that methodology. 14:51

In my evidence, I've identified several areas where I do not believe the historical trends demonstrate an accurate level of forecasting.

Q. Okay. I'm sure you've heard in the last few days that

some of the controversy is non-controllable costs and -- as well as capital project costs.

Are you aware of ways that other jurisdictions handle these type of things to be sure that overforecasting does not take place?

A. Any forecast by its very nature will not be exactly what you see in the actuals. My concern arises when there's a consistent pattern of overforecasting. When a utility has a reasonable methodology, my expectation is you would see variances because by the very nature forecasts are not precise. 14:52

But one would expect those variances to fluctuate on either side of the forecast.

In other jurisdictions, there are things that are done to try and mitigate that. In Alberta, we have gone through an extensive PBR methodology to try and change the way utilities behave. That's another discussion.

There are opportunities to test on a hearing basis like is done here. But, really, you know, in terms of preventing overforecasting, that's really in the hands of the Commission or the Board here as it assesses the record, looks at the history of the utility, and it comes up with what it thinks result in just and reasonable rates. And that's why I'm here presenting 14:52

my evidence, to provide a view of what I think has happened.

And this Board will then take that evidence, weigh it with the evidence of the utility, and come up with what it views as just and reasonable rates for utility customers in the Yukon to pay.

Q. Okay. Thank you.

Would you agree that such a thing as WIP, which is used in many jurisdictions, work in progress, would be useful deferral account to put these non-controllable costs into and as well as capital projects, until they are deemed used and useful? 14:53

A. **Well, work in progress or construction work in progress is an accounting construct. It's not a deferral account. When a project is initiated, the costs are gathered in work in progress. When the project is complete and put into service, it is moved from work in progress to plant in service.**

And so I believe YECL already uses work in progress as an accounting construct because it operates under Generally Accepted Accounting Principles and that is one of them, or one of the constructs that would be used. So I'm not really sure what you're asking, sir. I suspect YECL already uses work in progress as it's intended. 14:54

There are other constructs. In Alberta, the large transmission companies have a deferral account for projects that are directly assigned from the Independent System Operator or ISO. But those are very large projects that are not forecastable at all because they're based on the ISO long-term plan, which changes from time to time. And the utility really has no choice but to comply with the ISO plan.

There isn't really anything like that here. So I'm really not sure how you would do it. You could introduce more deferral accounts, yes; but that shifts risks from the utility onto customer, and I'm sure that's always a good thing either. 14:55

Q. Okay. Thank you.

That's what I was looking for, was maybe some type of remedy that other areas use to fix these problems that we're having here.

Basically the only other thing I have is that, in looking at your CV, that's the appendix of your evidence, you indicate that you have a lot of 14:56 experience in reviewing and testifying in other jurisdictions on rate applications.

So perhaps you could provide a specific reference to a regulatory proceeding where a utility has been found to overforecast its revenue requirement and maybe

remedies that the regulator used.

A. Well, each of the appearances, when it relates to a general tariff application, a portion of my evidence may have focussed on overforecasting. The remedy is -- in the jurisdictions I've dealt with -- and I believe this to be the same -- on a prospective-ratemaking basis, the remedy is to -- for the regulator to adjust the forecasts, to reduce the forecasts.

I don't believe there is a remedy that can go back and claw back or recoup any overforecasting. By the very nature of a future test period jurisdiction, once the revenue requirement is set, my understanding is that the utility then is -- is to operate its utility to create efficiencies and to benefit from those efficiencies. 14:57

That is one of the benefits of a future test period, is that the utility is incented to find efficiencies. The issue is were there's consistent overforecasting, then one has to question whether the utility is finding true efficiencies or is, in fact, using forecasting methodologies that should be changed. 14:57

So the remedy is for this Board to take note of the areas of overforecasting and adjust those portions of revenue requirement where it finds that, in fact, has been a systemic overforecasting.

Q. Very good.
MR. RONDEAU: Thank you so much.
THE CHAIR: Thank you.
Mr. Maissan.
MR. MARRIOTT: Mr. Chair, I think given the previous discussion and the questions that Roger asked, I don't think I have any questions that would be fruitful. Thank you.
THE CHAIR: Thank you.
Yukon Conservation Society? They have no questions? 14:58
MS. MIDDLER: No.
THE CHAIR: No.
And that's it, Mr. Williams. Would you like to...
MR. WILLIAMS: Sir, ATCO Electric Yukon has no questions for this witness.
THE CHAIR: Thank you.
Ms. Sabo.
MS. SABO: Thank you, Mr. Chair.
MS. SABO QUESTIONS THE WITNESS: 14:59
Q. Mr. Bell, I have a couple of questions to follow up with. I would like to take you to your IR responses to the Board. And it's Exhibit C-4. And I'm looking at IR Response 4 and -- 4(b). And the last paragraph of IR 4(b) on page 5.

A. I'm there, ma'am.

Q. Okay. And I was particularly interested in the first sentence you have there, which says: (as read)

> "If the Board wants to access the forecast costs, it could examine the forecast costs per new extension and compare that to historic actual costs per new extension."

A. I'm sorry, I'm not following. I thought I was there.

Q. Okay. It's your IR Response 4(b). 15:00

A. 4(b), as in Bob, yes.

Q. Yes. Last paragraph. And it's on its own on page 5.

A. That's my problem. I didn't go down one page far enough. Okay. I am there now.

Q. Okay. So in terms of that first sentence, sir, I thought this was an interesting concept, but I wondered how practical it would be to do that. Would you suggest that we do that on a one-time basis, or should we do that in each application, to look at the forecast cost per new extension and compare it to the historical 15:00 actual cost per new extension?

A. When I was writing this, I was thinking on an average. So it shouldn't be that onerous. It would be taking forecast capital additions and actual capital additions, looking at total new extensions in each

year, coming up with a cost per unit, and looking at the trend and the forecast as a way of assessing whether or not the forecast costs were within a reasonable range. I recognize that in any utility from one year to the next there can be a mix of different kinds of extensions, commercial, residential, multi-family, and things like that, so it's an indicator that allows you to get a sense of whether the forecast is in a realm of reasonableness.

Q. Okay. So we would still have the forecast as proposed. This additional component that you're recommending here would just be a reasonability check compared to that forecast? 15:01

A. Exactly.

Q. Okay. Thank you.

And my second question, Mr. Bell, relates to the question I asked ATCO Electric Yukon earlier today about forecasting accuracy and, given your evidence, what factors they would recommend in terms of looking at general forecasting accuracy or whether we should be looking at a more incremental level line-by-line analysis. 15:02

Were you in the room for that, sir?

A. Yes, I was.

Q. Okay. And I would ask you the same question. What

factors should we take into consideration looking at general forecasting accuracy or looking at line-by-line forecasting accuracy, for example, the new extensions that you've identified here? Can you help us how we should weigh those?

A. Absolutely. When a utility files an application, it files a detailed budget, if you will, or business plan for its test period. It uses a number of forecast methodologies and a number of ways to forecast different components of it. Some are based on average of historical costs. Others are based on expected workloads. And each utility does it differently.

If one were to just take the overall level of revenue requirement or forecast cost in the various components, you miss the subtleties of the different methodologies and you miss the fact that there may be a methodology that's producing an anomalous result, as I've identified in my evidence. And the utility should be incented to find better ways to produce forecasts. If a utility is constantly overforecasting in a certain area, it shouldn't be using that to offset bad forecasting on the other side in another area. It should be finding ways to forecast more accurately for each component.

15:03

15:03

That becomes even more important when you get into

Phase 2, where the different costs are charged to different customer classes, where you want accurate forecasts at an account level so that when you do do a Phase 2 application and you're developing rates for the various customer classes, each customer class is paying it's fair share of the costs.

If you just test forecast accuracy at a global level, you miss that nuance and aren't able to in fact derive fair rates on a customer-class-by-customer-class basis in a Phase 2 application. 15:04

Q. Okay. Any other considerations we should take into account when looking at general forecasting accuracy versus the line by line --

A. Well, in my mind, whenever I've read a regulatory decision, it's not a bucket-of-costs approach that has used. It's being a line-by-line approval thing, saying we agree with the FTEs, we agree with these capital projects, that you have evidence that you need to do them. We agree that the increases in costs for vegetation management should go up because of these considerations. 15:05

And so the decisions are rendered at a line by line -- or close to a line-by-line item. And so you're testing the forecast at a line-by-line basis at a reasonableness level anyways. And so it makes more

sense, then, to rule on that. And where there's a forecast that's off, adjust the forecast in your decision.

Q. Thank you, Mr. Bell. Those are my questions. We appreciate you attending today.

A. Thank you, ma'am.

THE CHAIR: Do any members have any questions? Mr. Marriott, do you have anything for your panel?

MR. MARRIOTT: No, thank you, sir.

THE CHAIR: Then this panel is -- we thank you for your attendance and... 15:05

A. Thank you, sir.

THE CHAIR: You're free to go.

A. Thank you, sir.

(WITNESS STANDS DOWN)

THE CHAIR: So where are we at now, Ms. Sabo?

MS. SABO: If I could get my mic on, maybe we could adjourn for the day. Chairman Laking, I don't have anything further. I think we just need to thank everybody for attending and if you have anything to add to that. We appreciate everybody's time over the past weeks of preparation the last few days in the hearing room. 15:06

MR. MARRIOTT: Sir, there is one thing, and I don't know that I would necessarily exercise this

right, but Mr. Coyne gave some undertakings and provided those answers after he left. If anybody had any follow-up in writing, maybe you could set a date for that. For me, Monday would be fine. I'm not sure I'm going to have any, but I would like an opportunity to kind of go over what he did say and see if there's anything arising. And then there would be, if you're going to do that, another date for him to respond, which Mr. -- ATCO Electric's counsel could speak to what would be reasonable. Maybe he hasn't spoken to Mr. Coyne, I don't know. 15:07

THE CHAIR: Well, there's a couple of other undertakings I think as well. Maybe the -- there might be some follow-on things on those, so maybe we could set a window for those written things.

MS. SABO: I think Mr. Marriott is right. Maybe Mr. Williams can give us an idea on timing, and we can set some dates.

THE CHAIR: Please.

MR. WILLIAMS: I think sometime next week should be fine. I think any time after about -- 15:07

Mid next week?

-- about mid next week we should be able to have all of our undertakings in, and then maybe it makes sense to set a date, maybe the start of the following

week, for any additional questions to be provided, if there are any.

THE CHAIR: So suggesting the 9th to get all of the material in. That's Wednesday?

MR. WILLIAMS: Yes, sir. That sounds about right.

THE CHAIR: And then questions from that by the following Monday, the 7th? Does that work?

MS. SABO: The 14th.

THE CHAIR: 14th. Yes, sorry. I'm going backwards. 14th. 15:08

And then responses to that? What are we thinking, two, three days?

MR. WILLIAMS: Sorry, sir. We're saying Monday the following week, so the 14th?

THE CHAIR: Yes. So 9th would be to get the material in. 14th would be the questions. That's a Monday.

MR. WILLIAMS: I think one week from there would be more than sufficient. 15:09

THE CHAIR: The 21st?

MR. WILLIAMS: Yes, sir.

MS. SABO: Argument's due to the 24th. So parties might need a little extra time to review that. So maybe instead of the 21st, we could pick the

Thursday or the Friday before.

THE CHAIR: Can we live with the 17th, which is --

MR. WILLIAMS: Why don't we go with that for now, and if something arises that's a significant question that we may need a bit more time, we can deal with that at that point in time.

THE CHAIR: We're looking for all of those materials to come in by the 9th. And questions on the 14th, and answers for the 17th. And then we have argument on the 24th, is -- according to the schedule now. 15:09

MR. MARRIOTT: I think that schedule works for the City.

MR. WILLIAMS: No issues with that, sir.

THE CHAIR: Okay. Any other parties have an issue with that schedule?

MR. RONDEAU: No problem.

THE CHAIR: Okay. Seeing none, then I thank everyone for their attendance at this proceeding, and we'll see you in the write-ups. 15:10

MR. MARRIOTT: Thank you very much.

MR. WILLIAMS: Thank you.

THE CHAIR: Thank you.

(PROCEEDINGS ADJOURNED AT 3:10 P.M.)

PROCEEDINGS CONCLUDED

Certificate of Transcript

We, the undersigned, hereby certify that the foregoing pages 393 to 554 are a complete and accurate transcript of the proceedings taken down by us in shorthand and transcribed from our shorthand notes to the best of our skill and ability.

Dated at the City of Whitehorse, Province of Yukon, on November 3, 2016.

"Danielle Harmata"

Danielle Harmata, CSR(A)

Official Court Reporter

"Adele Jones"

Adele Jones, CSR(A)

Official Court Reporter

- I N D E X -

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Yukon Utilities Board

Board Order 2017-01
Appendix A: Reasons for Decision
April 27, 2017

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1 Introduction

1. On May 11, 2016, pursuant to the *Public Utilities Act* and Order-in-Council 1995/90, the Yukon Electrical Company Limited (YECL or Applicant),[1] carrying on business as ATCO Electric Yukon (AEY), filed an application with the Yukon Utilities Board (Board) requesting an order approving forecast revenue requirements for the years 2016 and 2017 (test period) (Application). AEY is seeking approval of a revenue requirement of $53,890,000 for 2016 and $56,173,000 for 2017. The applied-for revenue requirement represents cumulative rate increases of 4.4 percent for 2016 and 7.5 percent for 2017, and year-over-year rate increases of 4.4 percent and 3.1 percent respectively.

2. Additionally, AEY sought approval of:
- an interim refundable rate rider of 11.62 percent, effective July 1, 2016;
- the continued use of currently approved deferral accounts, including purchase power flow-through, fuel price flow-through, and defined benefit pension costs during the test period; and
- new deferral accounts related to liquefied natural gas (LNG) fuel price changes, statutory tax rate changes, feasibility studies, and costs arising from Board Orders or legislative provisions not currently contemplated.

3. AEY is a private investor-owned utility serving more than 17,000 customers in 19 communities in the Yukon. AEY purchases power from Yukon Energy Corporation (YEC) for distribution to customers in Whitehorse, Marsh Lake, Tagish, Teslin, Haines Junction, Carmacks, Stewart Crossing, Pelly Crossing, Carcross, Keno, Ross River, Canyon Creek and a variety of rural areas surrounding Whitehorse. The company maintains backup generating plants in Carmacks, Teslin, Haines Junction, Ross River, Pelly Crossing and Stewart Crossing in the event of a power interruption. AEY also owns and operates the Fish Lake Hydro plant which generates power, and generates and distributes power in Old Crow, Beaver Creek, Destruction Bay, Burwash Landing, Upper Liard, Watson Lake and Swift River.

4. On May 27, 2016, the Board issued Board Order 2016-01, in which the Board ordered AEY to publish a Notice of Application and Hearing for the General Rate Application (GRA) no later than June 3, 2016 in appropriate local news publications in AEY's service area to provide adequate notice to the public. AEY was also directed to make the Application and supporting materials available on its website: www.atcoelectricyukon.com, as well as in hardcopy upon request to AEY. Board Order 2016-01 set out a process schedule, pending ministerial approval, for the Application, with a hearing to commence on November 1, 2016.

5. On June 17, 2016, the Minister of Justice authorized the Board to incur the expenses necessary to conduct a public hearing into the Application pursuant to section 50 of the *Public Utilities Act*.

[1] Yukon Electrical Company Limited is the legal entity, and ATCO Electric Yukon is the brand name that is now used for the company's utility service operations in Yukon.

6. The Board, through Board Order 2016-02, issued June 24, 2016, granted intervener status for this proceeding to the following:

- City of Whitehorse (CW)
- John Maissan (JM)
- Utilities Consumers' Group (UCG)
- Yukon Conservation Society (YCS)
- Yukon Energy Corporation (YEC)

7. In Board Order 2016-02, the Board also approved a 9.41 percent interim, refundable rate adjustment rider, effective July 1, 2016. Subsequently, in Board Order 2016-02 Errata, the Board changed the interim rate adjustment rider to 11.62 percent, in order to account for a calculation error.

8. In its intervener registration letter, dated June 17, 2016, and subsequently, UCG indicated that it had contacted the Pacific Economics Group (PEG) to help UCG determine if it was possible to benchmark the costs and productivity of AEY. UCG requested that the Board issue a letter to PEG so it can be assured that it would have an opportunity to access recovery of its costs through the cost claims process set by the Board. UCG also indicated that the process schedule would need to be altered to allow for a series of interrogatories to determine if benchmarking was possible.

9. On June 21, 2016, the Board set out a process to address UCG's request. Submissions were received from AEY and UCG. On July 4, 2016, after consideration of the UCG request and parties' submissions, the Board, in Board Order 2016-03, denied the UCG request for a letter of comfort to PEG. No revision to the process schedule was required.

10. On August 12, 2016, UCG submitted a motion requesting that the Board issue an order requiring AEY to provide adequate responses to certain UCG Information Requests (IRs). The Board invited comments from AEY on the UCG motion and reply comments from UCG. In Board Order 2016-04, issued on September 2, 2016, the Board ruled on the UCG motion and directed AEY to provide further and better information responses by September 9, 2016. In that Board Order, the Board amended the process schedule to allow UCG to file its evidence after the receipt of the additional information responses.

11. The Board held an oral public hearing in Whitehorse, Yukon from November 1 to 3, 2016. The Board was comprised of Robert Laking, Chair, and members Andre Fortin, Meagan Hannam, Bonnie King and Phillip Fitzgerald.

12. At the hearing, the Board confirmed that Final Argument was due on November 24, 2016 and Reply Argument on December 15, 2016. The Board considers the record of the proceeding closed on December 15, 2016.

13. In reaching the determinations contained within this Board Order, the Board has considered all relevant materials of which the record of this proceeding is comprised, including the evidence and argument provided by each party. Accordingly, references in this Board Order to specific parts of the record are intended to assist the reader in understanding the Board's reasoning related to a particular matter and should not be

taken as an indication that the Board did not consider all relevant portions of the record with respect to that matter.

2 AEY Sales and Revenue

2.1 Overview

14. AEY stated that its sales and revenue forecast was based on a detailed analysis of historical sales data at the community level and takes into account the most recent data available at the time the forecast is prepared. This data consists of information gathered by AEY staff who work in the communities as well as information resulting from consultation with the City of Whitehorse, Yukon government officials and various local agencies and developers.

15. The following table summarizes AEY's energy sales forecast for 2016 and 2017 by customer class, along with the corresponding actuals for 2013 to 2014, and 2015:

Table 1. **AEY energy sales by customer class – 2013 to 2017 (MWh)**

Customer class	Actuals			Forecasts (Test Period)	
	2013	2014	2015	2016	2017
Residential	148,780	147,253	148,605	147,111	151,617
Commercial	159,322	154,709	155,346	152,187	153,336
Street Lights	3,719	3,765	3,886	3,944	4,008
Private Lights	551	544	519	492	472
Total Retail Primary	313,372	306,272	308,356	303,735	309,433
Secondary Sales	3,959	5,415	7,030	9,429	9,429
Wholesale Sales	356	495	430	427	427
Total	316,687	312,182	315,816	313,592	319,289

Source: Application, Table 1, page 2-1.

16. Due to the changes in the energy sales by customer class, AEY's total primary non-industrial sales are forecast to decrease by 1.5 percent in 2016, and increase by 1.9 percent in 2017.

17. AEY provided an update to its test-period sales forecast to include nine months of actuals to September 30, 2016, as shown in the following table:

Table 2. **AEY updated test period sales forecast by customer class (MWh)**

Customer Class	Forecasts (Test Period)	
	2016	2017
Residential	146,698	153,275
Commercial	153,635	154,639
Street lights	3,922	3,978
Private lights	496	480
Total retail primary	304,751	312,373

Secondary sales	9,429	9,429
Wholesale sales	427	427
Total	314,607*	322,229

Source: Exhibit B-20, AEY undertaking; *Corrected for addition.

2.2 Views of the Applicant

18. In 2015, AEY provided electricity services to approximately 17,600 non-lighting customers in its service area and supplied a total of 308.4 GWh to residential, commercial and lighting customers. This represents an increase in total primary sales of 0.7 percent from 2014 levels. This increase follows decreases of 2.0 and 0.6 percent respectively in 2014 and 2013, from prior year levels.

19. After experiencing strong growth in the Yukon from 2004 to 2012, AEY submitted that the pace of economic activity in the Yukon has slowed down significantly. Slower population growth has also contributed to minimal customer gains in the residential and commercial sectors of AEY. It expected that the overall impact of the economic and population growth slowdown to continue to impact AEY's customer growth and sales over the test period.

20. AEY added that its demand-side management (DSM) program and the Yukon government's energy initiatives, such as those related to the commercial energy incentive program and micro-generation, which were introduced in the Yukon over the last few years, have also contributed to lower electricity sales experienced in the period from 2013 to 2015.

21. AEY reviewed its two-step approach for determining weather-normalized use per customer (UPC), where:

> In the first step, the historical average monthly UPC is regressed on actual monthly Heating Degree Days (HDD), and in the second step, the coefficient of HDD from the regression in the first step is multiplied by the difference between the actual HDD and the "Normal" HDD.[2]

22. In its Application, AEY proposed to update the timeframes used to determine the weather-normalized UPC. The existing methodology uses a longer time period and the proposed methodology uses the last three years of data, as illustrated in the table below:

Table 3. **Comparison of weather-normalized UPC methodologies**

	Regression data for UPC (Step 1)	**"Normal" HDD (Step 2)**
Prior Methodology	15 years	20-year average
Current Methodology	3 years	3-year average

Source: Application, page 2-5.

[2] Exhibit BB-1, Application, page 2-5, lines 3-7.

23. In the proposed methodology, AEY would apply the growth rates experienced over the period from 2013 to 2015 to derive the forecast UPC for the test period.

24. In support of its proposal, AEY stated:

> … over the past few years, in addition to changes in electric heating, there has been an increase in energy efficiency programs in the Yukon such as Demand Side Management and the Commercial Energy Incentive program. These trends, combined with a decline in economic activity and increasing effects of global warming have contributed to an overall downward trend in UPC over the 2013-2015 time period.[3]

25. AEY submitted that using the 2013 to 2015 timeframe for weather-normalizing and forecasting the UPC was more appropriate, as it encompasses trends occurring in the Yukon over the last few years.

2.2.1 Residential sales forecast

26. Respecting its residential sales forecast, AEY stated that the forecast has two key inputs: net customer additions and the UPC. The energy sales forecast is obtained by multiplying the forecast number of customers, which includes all known residential property developments, by the weather-normalized UPC forecast.

27. AEY submitted that the residential average UPC for all communities (except for Keno City, Stewart Crossing and Swift River) is calculated by using the weather-normalized UPC of the previous year as a base and applying the 2013 to 2015 growth in weather-normalized UPC. For Keno City, Stewart Crossing and Swift River, AEY used the actual UPC of the previous year as a base[4] and applied the 2013 to 2015 growth in actual UPC. AEY explained that actual UPC for these communities was "used because there are very few customers in these communities and there is poor correlation between their average UPC and temperature."[5] The community energy sales forecast is then calculated by multiplying the forecast community customer counts by the respective community UPC forecast.

2.2.2 Commercial sales forecast

28. Similar to the residential sales forecast, the commercial sales forecast has two key inputs: net customer additions and the forecast UPC. The energy sales forecast is determined by multiplying the forecast number of customers (based on the net customer additions forecast) by the UPC forecast.

29. AEY stated that Whitehorse's commercial UPC for the test period is forecast using the weather-normalized UPC of the previous year and applying the 2013 to 2015 growth in weather-normalized UPC. AEY added that it expects three new large commercial customers to be added during the test period in Whitehorse. AEY added:

[3] Exhibit BB-1, Application, page 2-5, lines 14-19.
[4] Exhibit B-9, YUB-YECL-7 (a): "For the purpose of forecasting the 2016 UPC, 2015 is considered to be the previous year. For the purpose of forecasting the 2017 UPC, 2016 is considered to be the previous year."
[5] Exhibit BB-1, Application, page 2-6, lines 11-12.

> ATCO Electric Yukon has considered these new large customers individually, and has forecast the load each customer will bring to the system each year based on the start-up time and other pertinent information provided by the customer. The commercial energy sales for Whitehorse are then calculated by adding the specific energy sales of the new large commercial additions to each of the test years.[6]

30. With the exception of Whitehorse, AEY submitted that the commercial UPC forecast for all communities is determined by using the actual UPC of the previous year, and applying the 2013 to 2015 growth in actual UPC. AEY explained that actual UPC is used because there are fewer commercial customers in these communities or there is poor correlation between their average UPC and temperature. The community energy sales forecast is then calculated by multiplying the forecast community customer counts by the respective community UPC forecast.

31. In response to UCG, AEY reiterated that three main factors have contributed to the declining trend in residential and commercial UPC, and these factors support the updated forecast methodology. These are:

(a) the economic slowdown in the Yukon;

(b) a continuous warming trend, starting in 2013; and

(c) recent energy conservation initiatives, which have been implemented in the Yukon.

32. AEY added that the proposed change from 15 years to three years to run its regression model for UPC and HDDs results in a more accurate portrayal of the current context in which AEY operates, and is necessary in order to appropriately account for the factors that have led to the change in UPC behaviour since 2012.[7]

33. During the oral hearing, AEY updated its sales forecasts to incorporate nine months of actuals, as of September 2016. The updated sales forecast provided in a table in response to the undertaking showed energy sales to be with 0.3 percent of actuals.[8]

2.2.3 Views of interveners

34. Mr. Maissan noted that residential and commercial sales are expected to decrease slightly in 2016 and then increase modestly in 2017. Mr. Maissan further noted the secondary sales were forecast to increase by 2.4 GWH in the test years. Mr. Maissan recommended that the Board accept AEY's sales forecast as filed.

35. UCG pointed out that AEY has consistently realized sales that were below the approved amounts. UCG submitted that this is in part due to AEY's forecasting methodology, as well as under-estimating the impact of weather, the economy and DSM initiatives. Given the downturn in the Yukon economy and the uncertainty created by a new territorial government, UCG submitted that AEY had erred in simply applying the

[6] Exhibit BB-1, Application, page 2-6 (lines 26 to 27) to page 2-7 (lines 1 to 3)
[7] YECL Final Argument, paragraph 24.
[8] Transcript, Volume 2, November 2, 2016, page 347, lines 1 to 4.

sales growth rates experienced over the 2013-2015 period to derive the weather-normalized UPC for the test period.[9]

36. UCG submitted that AEY should be directed to update its most recent sales forecast provided in its undertaking found at Exhibit B-2 with actuals from 2016 and 2017. This update should be provided when AEY submits its compliance filing and should use the most recent actuals and forecast to determine revenue requirements.

2.2.4 Views of the Board

37. The Board notes that AEY argued that the major reason for the shift in timeframe from 15 years to three years regarding its running of the regression model for UPC and HDDs was due to the shift and the change in direction respecting UPC starting in 2012.[10] AEY has affirmed the contributing factors as being the downturn in the economy and conservation initiatives.[11]

38. The Board finds that recent trends in the Yukon underpin AEY's proposed change in its methodology but the Board has concerns that a recent trend may or may not be reflective of future forecasts required in a test period. The Board considers it important that a methodology be adopted that is representative of energy sales and reflective of UPC and HDD in future years. The Board has concerns that if, for example, there is economic growth prior to the next GRA, a further adjustment to the methodology will be required due to a short time period being used to forecast energy sales.

39. With respect to its updated sales forecast, AEY's original forecast was within 0.3 percent compared to actuals for the 2016 test year. However, the Board notes that there is a one-percent variance in total retail primary sales for 2017 when the updated forecast is compared to the original forecast.

40. The Board notes AEY's submission that, "Had AEY not revised its methodology… AEY's sales would have varied by more than 1.1% when compared to actuals, as of September 2016."[12] Given these submissions on the 2016 and 2017 numbers, the Board understands that the acknowledged differences using the old or new methodologies would not be significant. Considering the above, AEY has not satisfied the Board that its proposed methodology with respect to using three years for regressing data and normalizing HDD, as well as using the 2013 to 2015 growth rates to derive the forecast UPC, should be adopted. The Board accepts AEY's position that 15 or 20 years may be too long of a timeframe to use in calculating energy sales but it is not convinced that three years is correct for regressing data and normalizing HDD. AEY provided testimony during the course of the hearing that ATCO Gas uses a 10-year timeframe for normalizing over the years to represent more current data.[13] Accordingly, the Board directs AEY, in its compliance filing, to refile its sales and revenue forecast,

[9] UCG Final Argument, paragraph 76.
[10] Transcript, Volume 2, November 2, 2016, page 341 (line 24) to page 342 (line 2).
[11] Transcript, Volume 2, November 2, 2016, page 342, lines 4 to 22.
[12] AEY Final Argument, paragraph 26.
[13] Transcript, Volume 2, November 2, 2016, page 343, lines 17 to 20.

incorporating its prior methodology[14] using a 10-year timeframe for UPC regression and normalizing HDD.

3 Purchase power

41. AEY submitted that its primary and secondary purchase power costs are forecast to remain relatively flat over the test period. The following table shows the actual and forecast purchase power over the period from 2013 to 2017:

Table 4. **Actual and forecast purchase power – 2013 to 2017 ($000s)**

	Actuals			Forecasts	
	2013	**2014**	**2015**	**2016**	**2017**
Primary Purchase Power	25,552	24,503	24,725	24,451	24,921
Secondary Purchase Power	292	415	454	415	415
Less: Capitalized[15]	(402)	-	(72)	(110)	(86)
Total Purchase Power[16]	25,442	24,918	25,107	24,756	25,250

Source: Exhibit BB-1, Application, page 3-1.

42. The purchase deferral account is related to increases or decreases to the cost of purchased power, which is based on YEC's rates for primary energy sales and secondary sales.

43. AEY submitted that the test period purchase power forecast takes into account the Fish Lake hydro generation output, which is based on the lifetime average output for Fish Lake Unit #2 from 1960-2015 plus the two-year average for the new Fish Lake Unit #1 adjusted for planned decreases in generation due to capital builds.[17] The drivers of the forecasts for 2016 and 2017 were stated as:

> The 2016 and 2017 capital that are causing short term reductions in generation are the replacement of Ditch 1 due to the spillway failure and the Fish Lake Ditch 3 Diversion Replacement in 2016. In 2017, water flows will be reduced for the Fish Lake #2 Head Pond Spillway Replacement and the Fish Lake Unit 1 Spillway Diversion Structure.[18]

44. Furthermore, consistent with the approach approved in Board Order 2014-06, AEY submitted that lines losses are calculated on a five-year average and total 6.2 percent.[19]

[14] The methodology used in its 2013-2015 GRA.
[15] Exhibit BB-1, Application, page 3-1, footnote 1: "Consistent with Board Order 2009-2, AEY will continue to capitalize the incremental purchased power costs for decreased hydro supply resulting from capital builds and rebuilds."
[16] Rider J has not been included, as these are flow-through amounts to YEC.
[17] Exhibit BB-1, Application, page 3-1 (lines 17-18) to 3-2 (lines 1-2).
[18] Exhibit B-9, YUB-YECL-9(a).
[19] AEY Final Argument, paragraph 31.

3.1 Views of interveners

45. UCG submitted that the incremental purchased power costs to be capitalized should only relate to planned capital projects and not maintenance or other projects that were not included in the capital budget reviewed by the Board.[20]

3.2 Applicant responses to interveners

46. In response to UCG's submission, AEY stated that its understanding of Board Order 2009-02 is consistent with UCG's on this matter.

3.3 Views of the Board

47. The Board's determination in Board Order 2009-02 respecting the capitalization of purchase power costs required because of the Fish Lake hydro was based on "YECL's Fish Lake generation forecasts as well as the expensing of purchase power costs associated with Fish Lake hydro rebuilds."[21] The Board directed AEY, at the time of its next GRA, to provide clear documentation of these incremental power purchases due to the Fish Lake hydro rebuilds.

48. In the current Application, AEY has capitalized the forecast purchased power costs related to the Fish Lake hydro rebuilds for 2016 and 2017. In the Board's view, this is consistent with directions provided in Board Order 2009-02:

> The Board acknowledges that enduring benefits will be provided to the facility and ratepayers as a result of the Fish Lake hydro rebuild. Further, the Board notes the capital costs associated with the rebuild are to be amortized over time due to the enduring benefits. The Board considered the YECL witness response that the incremental purchase costs from WAF related to the rebuild could be capitalized. Therefore, the Board finds it reasonable to amortize the increased power purchase costs directly related to the rebuild project over time. *(footnotes omitted)*[22]

49. The Board approves the forecast primary and secondary purchase power costs as filed because the methodology used is reasonable and consistent with the previous GRA.

3.4 Deferral Account — Purchase Power Flow-Through

50. AEY requested a Purchase Power Flow-Through Deferral Account (PPFTDA). AEY noted that the cost of purchase power in the Application is based on rates from YEC for primary energy and secondary sales and do not include any adjustments due to YEC's energy reconciliation adjustment (ERA). Any increases or decreases to the YEC rates or any ERA adjustments are to be flowed through to customers.

3.4.1 Views of interveners

51. UCG acknowledged that a deferral account is a reasonable way to track unforeseen changes in costs related to purchased power. However, UCG submitted that

[20] UCG Final Argument, paragraph 89.
[21] Board Order 2009-02, Appendix A, Reasons for Decision, page 9.
[22] Board Order 2009-02, Appendix A , Reasons for Decision, page 10

AEY must ensure that it limits as much as possible the charges from YEC by actively participating in reviews of YEC revenue requirements and implementing DSM initiatives that reduce the need for purchased power.[23]

3.4.2 Applicant responses to interveners

52. AEY responded to the UCG submission that AEY has participated in YEC regulatory applications that impact both AEY's customers and its share-owners and will continue to do so. AEY also submitted that it expects to continue working collaboratively with YEC on initiatives that impact Yukon electricity customers.[24]

3.4.3 Views of the Board

53. The Board notes AEY's responses to IRs on the PPFTDA. More specifically, the Board takes note of the response to YUB-YECL-47(b), in which AEY stated:

> … under a PPFTDA, AEY would assume risk associated with sales volumes, however AEY would not assume risk associated with changes to the Wholesale purchase rate... AEY submits that a PPFTDA is much more efficient than speculating on potential changes in its Wholesale costs resulting from changes to the Wholesale rate.[25]

54. Further, AEY stated that this account will ensure that there is an additional margin[26] if sales are greater than forecast.[27] Parties were asked to comment on that additional margin in argument[28], but no comments were received.

55. The Board accepts the submissions of AEY that the PPFTDA will provide additional margin on sales that are incremental to forecast levels and that the use of a PPFTDA is more efficient. The Board considers the PPFTDA to be a more efficient mechanism for adjusting potential changes in wholesale costs, especially since there are material timing differences between YEC and AEY GRA filings. Therefore, the Board approves the requested AEY PPFTDA, without changes.

4 Fuel costs

56. Fuel costs included in the AEY Application are reproduced in Table 5 below:

[23] UCG Final Argument, paragraph 88.
[24] AEY Reply Argument, paragraph 27.
[25] Exhibit B-9, YUB-YECL-47(b).
[26] By allowing the PPFTDA, a positive margin is maintained on incremental sales as incremental costs are covered through the deferral account.
[27] Transcript Vol. 3, page 520, lines 19-23.
[28] Transcript Vol 3., page 518, lines13-19.

Table 5. **Actual and forecast fuel costs — 2013 to 2015 ($000s)**

	Actuals			Forecasts (Test Period)	
	2013	**2014**	**2015**	**2016**	**2017**
Fuel Costs	6,708	6,760	6,621	5,225	5,268

Source: Exhibit BB-1, Application, page 4-1.

57. AEY explained that it purchases fuel on an ongoing basis for each of its five isolated plants via a diesel fuel tendering process, where a vendor is selected to be the provider of diesel fuel to AEY. AEY further explained that it has modest generation and fuel requirements associated with standby units that generate power in the event of an interruption of power on the Yukon interconnected system. The standby units are located at Carmacks, Teslin, Haines Junction, Ross River, Pelly Crossing and Stewart Crossing.

58. AEY stated that the forecast cost decrease in 2016 is mainly due to lower fuel prices than previously approved, which are currently used as the base fuel prices in Rider F. AEY added that the fuel costs forecast is a function of forecast sales, line losses, plant efficiencies and delivered prices. The fuel-deferral methodology used for this account was described, as follows:

> The previously approved methodology for the fuel deferral uses GRA-approved community-based plant efficiencies (or 'heat rate', kWh / Litre) and the plant's monthly gross generation to determine the quantum of litres for the monthly fuel deferral calculation. The difference between the actual and GRA-approved price per litre is then applied to this number of litres to arrive at the fuel deferral amount for the month.[29]

59. AEY submitted that the variance between actual and forecast fuel prices is refunded to or recovered from customers by means of Rider F, a fuel-price flow-through rider.

4.1 Views of the Board

60. The Board accepts and approves AEY's fuel cost forecast, as filed. AEY is proposing to continue the deferral for fuel prices for the test period.

4.2 Deferral Account — LNG Fuel

61. Notwithstanding the above, if the Watson Lake bi-fuel project is approved, AEY anticipated that, beginning in the fall of 2017, generation will be based on a variable fuel mix of diesel and LNG. Accordingly, AEY submitted that it required a deferral account to track and subsequently refund or recover changes in costs due to the differential in actual LNG fuel prices and the price included in rates. AEY explained that:

> Similarly to the Diesel Fuel Deferral Account, the LNG Fuel Deferral Account will use the GRA-approved community-based plant efficiencies and the plant's monthly gross generation to determine the volume of litres of diesel equivalent

[29] Exhibit BB-1, Application, page 4-2, lines 20-24.

> for the monthly fuel deferral calculation. Actual diesel volumes used for the diesel fuel deferral account calculation will be subtracted from this volume, with remaining allowable litres of diesel equivalent for use in the calculation of the LNG fuel deferral. [30]

62. AEY went on to explain that the difference between the actual and GRA-approved price per litre of diesel equivalent is then multiplied by the remaining allowable litres of diesel equivalent to arrive at the LNG fuel-deferral amount for the month.

63. AEY proposed to include the LNG price variances in the Rider F deferral account, stating that the principles supporting a diesel price variance deferral are the same as those supporting an LNG price variance deferral or a fuel price variance deferral, namely:

- Commodity prices are subject to material fluctuations outside the utilities' control; and
- It is not in ratepayers', the Board's, or the utilities' interests to speculate on these price fluctuations. [31]

64. AEY argued that it is well within the Board's authority to approve deferral accounts in general. Furthermore, should the Board determine that the wording of the Order in Council does not allow for the inclusion of LNG price variances in the existing Rider F, AEY submitted that a new deferral account and subsequent rider should be approved. Such a rider should operate in the same manner as Rider F.[32]

4.3 Views of interveners

65. UCG noted that Rider F was last approved in Board Order 2012-02, dated February 29, 2012. Noting that the Board, in Board Order 2011-15, confirmed that Rider F applies to all diesel fuel consumed in a period, UCG submitted that it is unclear whether AEY has applied to the Board for the inclusion of LNG price variances in Rider F.

66. Given that AEY is not using LNG at this time and only anticipates using LNG-fuelled generators late in 2017, at the earliest, UCG submitted that the Board should not allow AEY to establish a LNG-related deferral account until a need is established and an application has been made to change Rider F.

67. UCG further submitted that the Board cannot approve the proposed changes to Rider F for fuel used in Watson Lake without changes to section 8 of Order-in-Council 1995/90 to account for LNG use.

4.4 Applicant responses to interveners

68. AEY responded that section 8 of Order-in-Council 1995/90 provides for fuel-price adjustments and sets out that the Board must allow AEY and YEC to adjust their rates to retail customers, major industrial customers, and isolated industrial customers to

[30] Exhibit BB-1, Application, page 4-3, lines 7-12.
[31] Exhibit B-6, UCG-AEY-22
[32] Exhibit B-6, UCG-AEY-22

reflect fluctuations in the price for diesel fuel, without the requirement for specific application to and approval from the Board. However, simply because AEY is entitled to flow-through diesel fuel prices without Board approval, it does not mean that it is somehow prevented, upon Board approval, from flowing through the impact of changes to LNG prices.

4.5 Views of the Board

69. Considering the Board's determination in section 9.7.2 of this decision with respect to the Watson Lake bi-fuel project, the Board does not approve the LNG deferral account.

5 Operations and maintenance (O&M) expense

70. For 2016 and 2017, AEY requested approval of O&M expenses, totalling $11.993 million and $12.181 million respectively. The following table shows forecast and actual amounts for the period 2013-2015, and the forecast for the test years:

Table 6. **Operations and maintenance expense ($000)**

2013		2014		2015		2016	2017
Approved	**Actual**	**Approved**	**Actual**	**Approved**	**Actual**	**Forecast**	**Forecast**
11,604	11,718	11,882	11,698	11,944	11,616	11,993	12,181

Source: Exhibit BB-1, Application, Schedule 5.1

5.1 Labour

71. In the Application, AEY forecasted a complement of 70.38 full-time equivalents (FTEs) for each of the test years. This was an increase of 1.25 FTEs over the actual complement at the end of 2015.

72. AEY discussed labour costs in section 5 of the Application and stated that labour costs are calculated by multiplying the number of staff per job class by the rate of pay for each job class. The labour costs are then distributed to O&M accounts or capital accounts, depending on the nature of work being performed by the staff in the job class. Further, in section 1 of the Application, under the heading "Key Assumptions", AEY provided the following:

Table 7. **Key Assumptions**

	2016	2017
Labour inflation	3.25%	3.00%
Other inflation	2.20%	2.20%
Vacancy rate	4.00%	4.00%
Long-term debt rate	4.35%	4.85%

Source: Exhibit BB-1, Application, page 1-5.

5.1.1 Labour complement

73. AEY proposes a labour complement of 70.38 FTEs for each of the test years.

5.1.2 Views of interveners

74. Interveners did not provide any direct comments with regard to AEY's labour complement levels.

5.1.3 Views of the Board

75. Staff complement is one of the elements reviewed by the Board in relation to labour costs and the Board is concerned with the escalation of labour costs and the growth of Administration and General (A&G) costs. In this Application, AEY has requested an increase in its complement by two positions (an Engineering Technologist (1 FTE) and a Supervisor, Business Support Services (0.25 FTE)).

76. Regarding the existing financial analysts, the Board notes that the reasoning AEY provided for this change[33] in the supervision of these two positions was to have these analysts more tightly tied to northern operations and northern communities, as opposed to the previous reporting structure. AEY added that those positions work solely for AEY.[34] This rationale is not accepted by the Board because it is unclear how this supervisor position, which is to be based in Yellowknife, is to supervise the work of financial assistants who are based in the Yukon and whose work is carried out entirely in the Yukon, when these positions previously reported to a positon that was tied to AEY operations. Further, AEY has not demonstrated that the other primary function (accounts payable and accounts receivable duties) identified for the Supervisor, Business Support Services, cannot be completed by staff at AEY.[35] Additionally, AEY has not provided any explanation of why the supervisory duties of the Supervisor, Business Support Services could not be carried out by any of the existing accounting positions within AEY. Therefore, the Board concludes that the need for the Supervisor, Business Support Services position has not been justified and directs the positon be removed from AEY's complement.

77. As of the close of record, the Engineering Technologist position has yet to be filled. AEY did not provide any evidence that the work forecast for the Engineering Technologist position was not already being done by any of the other two existing engineering technologist positions or other members of the two engineering groups.

78. In Board Order 2014-16, AEY was directed to remove the corporate accountant position (1 FTE). It did not do so and did not request a review and variance of that direction.[36] To continue the position or rename the position as an Operational Accountant ignores the direction and concerns of the Board.

79. Therefore, AEY's requested approval for a complement of 70.38 FTEs for both test years is not approved. The Board approves a complement of 68.13 FTEs. The

[33] Referring to the change from reporting to the Manager (Whitehorse-based) to the Business Support Services Supervisor (Yellowknife-based).
[34] Transcript Vol 2, page 365, lines 1-13.
[35] Exhibit B-9, YUB-YECL-34(a).
[36] Transcript Volume 2, page 372, lines 1-17.

complement level of 68.13 FTEs is determined by removing the Engineering Technologist position (1 FTE), the Supervisor, Business Support Services position (0.25 FTE), and the Corporate/Operational Accountant position (1 FTE) as directed in the 2013-2015 GRA. AEY is to reflect this finding in its compliance filing to this decision.

5.2 Vacancy rate

80. As noted above, AEY has forecasted a vacancy rate for each of the test years of 4.0 percent, or approximately three FTEs. AEY said that the vacancy rate is based on a five-year historical average and is consistent with the methodology approved in Board Orders 2009-02 and 2014-06.

5.2.1 Views of interveners

81. Interveners did not comment on AEY's proposed vacancy rates.

5.2.2 Views of the Board

82. The Board has reviewed the submissions of AEY on its vacancy rate in this proceeding. The Board finds the vacancy rate requested is reasonable because it is based on a five-year historical average and is consistent with the methodology approved in Board Order 2009-02 and applied in Board Order 2014-06.[37] For these reasons, the Board approves a vacancy rate for AEY of 4.0 percent for each of the test years.

5.3 Labour inflation

83. AEY stated that the labour escalation for 2016 was based on AEY's existing collective agreement which covers in-scope employees and AEY applied the escalators in that agreement to both in-scope and out-of-scope employees.

84. AEY reiterated its submission from the Application (section 5) that its inflationary increases were consistent with several decisions in Alberta.[38] It added that AEY was appropriately staffed and did not undergo the growth incurred by ATCO Electric prior to the economic downturn in Alberta; therefore, it was not impacted by the economic downturn in Alberta or the ATCO Group reorganization.[39]

5.3.1 Views of interveners

85. In argument, interveners did not make any specific comments on labour inflation. However, in Reply Argument, UCG stated "… it is inconsistent to have labour inflation rates from another jurisdiction dictate what Yukoner ratepayers should pay when Yukon-specific labour and wages information is readily available. UCG submits that AEY's labour inflation should be held to the most recent Yukon statistics available."[40]

[37] Appendix A to Board Order 2014-06, section 5.2.2, page 23.
[38] AEY noted the following decisions in its argument: 3539-D01-2015 (EPCOR Transmission 2015-2017 Tariff), 3577-D01-2016 (ATCO Pipelines 2015-2016 GTA), 20407-D01-2016 (EPCOR 2014 True-Up and 2016-2017 Forecast Capital Tracker) and 20555-D01-2016 (ATCO Electric Distribution 2014 True-Up and 2016-2017 Forecast Capital Tracker), at paragraph 66 of AEY's Final Argument.
[39] AEY Final Argument, paragraph 68.
[40] UCG Reply Argument, paragraph 20.

86. In addition, several of the interveners expressed concerns regarding AEY's costs. CW was concerned with AEY's pattern of over-forecasting.[41] John Maissan observed that AEY is able to control overall O&M costs.[42] UCG supported CW's concerns regarding over-forecasting, additionally mentioning "artificial inflation of rates".[43]

5.3.2 Views of the Board

87. The Board notes that, in the September 9, 2016 updated response to YUB-YECL-27(a), AEY stated that in 2015, 10 employees (15 percent of staff) did not receive wage increases, and in 2016, 11 employees (17 percent of staff) did not receive wage increases.

88. In response to Board questioning, AEY confirmed that the staff who did not receive wage increases in 2015 and 2016 were all out-of-scope employees.[44] Further, AEY stated that for the 2016 and 2017 test years, the labour inflation forecast was based on AEY's existing collective agreement, which expires on December 31, 2016. The labour-escalation rate for the test period is forecast to be 3.25 percent. AEY did not submit any information that a new collective agreement had been reached or would be in place for January 1, 2017. The Board considers that the 2017 forecast labour escalator is not based on a collective agreement that would be in force in 2017.

89. The Board notes that built into the determination of revenue requirement for 2015 was labour inflation of 3.5 percent. However, out-of-scope employees did not receive inflation increments for that year, nor for 2016. In-scope employees received 2015 and 2016 labour-inflation increments of 3.25 percent. For 2015, this was 0.25 percent lower than what was built into the 2015 revenue requirement.

90. As a result, for out-of-scope employees, the Board awards, for 2016, a labour-inflation increment of 0.0 percent because out-of-scope employees did not receive inflationary increments. AEY is directed to reflect this change in its compliance filing to this decision.

91. For in-scope employees, the Board considered that a collective agreement was in place for the 2016 test period and approves the labour-inflation rate of 3.25 percent as requested for that year.

92. However, for 2017, since the Board has no evidence of the existence of a collective agreement, the Board has to determine the inflationary increase to be awarded for in-scope and out-of-scope employees. In making its determination, the Board considered the May 2016 *Yukon Economic Outlook.*[45] The Board notes that, based on the *Yukon Economic Outlook*, Yukon experienced an economic downturn in 2015 due to reasons such as:

- 2015 GDP was down by 3.8 percent;

[41] Exhibit C3-3, CW Evidence; CW Final Argument, paragraph 27.
[42] JM Final Argument, page 4.
[43] UCG Final Argument, paragraph 98.
[44] Transcript Volume 3, pages 400, line 16, to 401, line 8. .
[45] Exhibit B-9, YUB-YECL-30(a), Attachment 1.

- Average employment was down slightly;
- Unemployment rate was up 2.0 percent;
- Building permits were down 9.7 percent; and
- A modest decrease in the CPI for Whitehorse of 0.2 percent.

93. The preliminary forecast for 2017 discussed in the outlook is for Yukon's real GDP to fall by 5.7 percent, and employment and the labour force to be relatively flat. The Consumers Price Index (CPI) for Whitehorse is expected to be just under 2.0 percent.

94. For these reasons, the Board approves a 2017 labour inflation rate for in-scope and out-of-scope employees of 1.9 percent. AEY is directed to reflect this change in its compliance filing to this direction.

5.4 Pension matters

5.4.1 Defined Benefit Plan Contributions and Defined Benefit Pension Deferral Account

95. AEY provided the following placeholder amounts for pension costs in its Application:[46]

Table 8. **2013 to 2017 placeholder amounts for pension costs ($000s)**

	2013	2014	2015	2016	2017
	Actual	Actual	Actual	Test Period	
Defined Benefit	1,041	902	578	578	578
Defined Contribution	209	242	267	276	286
Total Pension Costs	1,250	1,144	845	854	864

Source: Exhibit BB-1, Application, page 5-3.

96. AEY sought Board approval for these amounts to be tied to the outcome of the upcoming ATCO Utilities Pension Application, to be filed before the Alberta Utilities Commission (AUC). In addition, AEY is seeking continuation of its pension deferral account to flow-through any increases or decreases to the defined benefit funding amounts as a result of any updated actuarial evaluations. For the defined contribution pension plan, AEY noted that the company's contributions rate was set at 6.0 percent.[47]

97. In an update[48] to defined benefit pension costs, AEY stated the costs for 2016 are forecasted to be $505,000, assuming a COLA of 100-percent CPI.

98. Further, AEY confirmed that if the deferral account is granted for pension costs, ratepayers would experience "actual cost" rather than placeholder amounts[49] and also

[46] Exhibit BB-1, Application, page 5-3.
[47] Exhibit BB-1, Application, page 5-3.
[48] Exhibit B-9, YUB-YECL-36(f).
[49] Exhibit B-5, JM-AEY-9.

confirmed that AEY would exclude any amounts the AUC does not approve for inclusion in utility rates in the Alberta 2016 pension application.[50]

99. In argument, AEY submitted that the assumption for 2016 of the COLA at 100 percent is based on changed circumstances, as the pension has moved from an unfunded liability to a funding-excess position.[51]

100. In its submission, UCG recommended that if the defined benefit pension deferral account was to be continued, its intended use should be clear, along with how it is to be used.[52] No other interveners made submissions on pension costs or this deferral account.

5.4.2 Views of the Board

101. The Board finds the requested pension amounts are reasonable. As a result, the Board approves the revised defined benefit pension amounts of $505,000 for each of the test years. The Board also approves the defined contribution rate of 6.0 percent, to be applied to the labour rates determined in section 5.3.1 of this decision.

102. Further, the Board approves AEY's request to continue with the Defined Benefit Pension Deferral Account (DBPDA). The Board finds that adjusting for the result of the ATCO Utilities 2016 Pension Application is a reasonable approach because it will reflect actual pension costs.

5.5 Other Inflation

103. As noted in the key assumptions,[53] AEY has requested other inflation of 2.20 percent for each of the test years. AEY stated that this forecast for the 2016 test year was based on the *Yukon Economic Outlook* dated October 2015. AEY added that since no public forecast was available for Yukon for 2017, it applied the 2016 forecast for that test year.

5.5.1 Views of interveners

104. Parties did not provide any specific comments on Other Inflation.

5.5.2 Views of the Board

105. The Board notes that AEY provided the May 2016 *Yukon Economic Outlook* in an IR response.[54] In that document, the CPI forecast for Whitehorse for 2016 was 2.0 percent and just under 2.0 percent for 2017. The Board accepts the information provided in the May 2016 *Yukon Economic Outlook* because it is the most up-to-date information on inflation in Yukon on the record. Accordingly, the Board sets the Other Inflation rate for 2016 at 2.0 percent and at 1.9 percent[55] for 2017. AEY is directed to reflect this change in its compliance filing to this decision.

[50] Exhibit B-4, CW-YECL-15(b).
[51] AEY Final Argument, paragraph 71.
[52] UCG Reply Argument, paragraph 21.
[53] Exhibit BB-1, Application, page 1-5.
[54] Exhibit B-9, YUB-YECL-30(a), Attachment 1.
[55] Exhibit B-9, YUB-YECL-30(b).

5.6 Non-labour costs

106. Non-labour costs were discussed in the Application. Schedule 5-1 provided a summary of actual and forecast costs. Schedule 5-2 provided year-over-year variance explanations.

107. AEY stated that non-labour costs are forecasted in two parts: (1) ongoing operational and administrative activities, and (2) new programs or projects. AEY added that it was not forecasting any new programs or projects for this test period.[56]

108. For ongoing operational and administrative activities, the forecast was based on historic spending and adjusted for known changes in work to be completed in the forecast period.

5.6.1 Views of interveners

109. CW submitted evidence challenging the forecast accuracy of AEY, stating:

> When the actual costs are systematically lower than forecast, one must question the reasonableness of the forecasts. When the approved forecast is continually higher than the actual costs for a cost category or item, it means customers are paying for costs the utility will not incur. While the utility is entitled to benefit from efficiency gains in the test period, the regulator must ensure that savings are from efficiency gains, and not the result of over forecasting. When there is a continual pattern of over-forecasting, that usually means that there is an issue with the forecast, and the subsequent forecast should be adjusted. Further, these savings should be captured in the subsequent rate application, to the benefit of customers.[57]

110. CW asserted that a pattern of over-forecasting for the production, distribution and general functions existed.[58] CW recommended that production costs be reduced by 15 percent[59] and that distribution and general costs be reduced by $272,000 in 2016 and $369,000 in 2017.[60]

111. UCG argued that "… there has been a pattern of over-forecasting and artificial inflation of rates in 2013-2015 with respect to O&M costs related to AEY's production facilities ($938,000) and overspending on administration and general ($458,000)."[61] UCG noted the variance between approved and actual affiliate charges for the 2013-2015 period. It recommended that affiliate charges should be reduced by 25 percent.

112. John Maissan submitted that AEY is able to control overall O&M costs according to their actual sales relative to approved forecast sales. He recommended that forecasted O&M costs for the 2016-2017 test years should be reduced by 1.1 percent.[62]

[56] Exhibit BB-1, Application, page 5-3.
[57] Exhibit C3-3, CW evidence, A5, pages 2-3.
[58] Exhibit C3-3, CW evidence, A6, pages 3-4.
[59] CW equated the 15-percent reduction in production costs to be $314,000 in 2016 and $306,000 in 2017.
[60] Exhibit C3-3, CW evidence, A7, pages 4-5.
[61] UCG Final Argument, paragraph 98.
[62] JM Final Argument, page 4, point 6.

113. In Reply Argument, UCG submitted:

> … that AEY has not provided the Board or interveners any alternative but to review O&M cost components. The only way to justify AEY's claim that O&M should only be reviewed in aggregate is if AEY has presented an integrated business strategic plan upon which its O&M is based.[63]

114. With respect to production costs, CW stated:

> … that in assessing the likely accuracy of any forecast in the application, the Board can and should take into account a pattern of over-forecasting in areas where that can be demonstrated.[64] (*underlining omitted*)

5.6.2 Views of the Applicant

115. In argument, AEY stated:

> Furthermore, the Bell Evidence does not take into account the oral testimony provided by Mr. Massie where he described a forecasting process that continuously informs the process with the best available information. Adjustment to the process are made based on historical costs and known costs looking forward. As noted by Mr. Massie, adjustments have been made to accounts going forward and these changes are reflected in the 2016-2017 test year forecasts.[65] (*footnotes omitted*)

116. AEY later added that it is more appropriate to look at total O&M costs and not isolate only those functions that are experiencing increases. In terms of $/MWh and O&M cost per customer, AEY argued that those metrics are influenced by the level of retail sales and those sales were actually decreasing by 1.5 percent. The forecasted average annual O&M cost per customer is flat with historical actuals.[66]

117. In reply to CW, AEY noted that CW did not provide any evidence as to why its method of forecasting is appropriate for the O&M categories in question. AEY went on further to say that CW failed to account for inflationary increases, based on the table provided in its argument that AEY has a history of accurately forecasting its O&M expenses.[67]

118. In reply to John Maissan's recommendation that O&M costs should be reduced by 1.1 percent, AEY said Mr. Maissan's recommendation ignored inflation as well as known increases in excess of inflation.[68]

119. In Reply Argument, AEY challenged UCG's request that affiliate charges be reduced by 25 percent. AEY stated that the difference between 2014-2015 actual amounts for affiliate charges related to the change in service provider and that change was fully reflected in the forecast for each of the test years.

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[63] UCG Reply Argument, paragraph 17.
[64] CW Reply Argument, paragraph 7.
[65] AEY Final Argument, paragraph 54.
[66] AEY Final Argument, paragraphs 58-59.
[67] AEY Reply Argument, paragraph 33.
[68] AEY Reply Argument, paragraph 35.

120. Regarding Administration and General O&M costs per customer, AEY countered the UCG argument by referring to corrected tables filed on November 10, 2016 to replace the original response to CW-YECL-13 Attachments 1 and 2. The update showed Administration and General O&M costs per customer to be less for the 2017 forecast than the 2015 actual.

121. AEY stated that its submissions for Financial Reporting and Regulatory Support affiliate costs should be seen as reasonable in comparison to 2013 amounts, especially given the regulatory events expected in 2017.[69]

5.6.3 Views of the Board

122. The Board is of the view, based on the evidence of CW, that AEY appears to have, at a high level, over-forecasted for each year in the 2013-2015 period. The Board views each year separately and not in aggregate. The forecast for each year is driven by different assumptions and different stages of planned programs. However, the Board agrees with AEY that the high-level approach submitted by CW can be overly simplistic. It is beneficial to have such a high level review, but the trend uncovered by that type of review should be the starting point for further investigation and not taken at face value. From an O&M perspective, deviations can occur due to changes in the capital/O&M mix. Deviations can also be related to deferring planned programs or increased work in other functions. Identifying a trend is insufficient. Identifying root causes and making recommendations for specific accounts or functions are necessary.

123. The Board does not accept AEY's submissions that, when considering trends, the total level of O&M costs should be considered or that the review should be limited to those areas with cost variance at the account level. Because of this, the Board believes that a review should be undertaken at the function level for variances in trends, as an inter-relationship between accounts within a function may exist. These inter-relationships may result in misleading trends. Further, at the function level, each function is independent; unless a link is specifically demonstrated, the cost causation in one function does not necessarily lead to cost causation in another function. As a result, the Board directs AEY in its compliance filing and in future GRAs to provide a labour schedule showing total labour costs as well as a breakdown of those labour costs into capital and each of the O&M and A&G functions. This labour schedule is to be provided for each of the test years and the three years prior to the test period. The prior periods will show a labour comparison between forecast and actual.

124. The Board notes that AEY bases its forecast on historical information, taking into account variance explanations from prior forecasts, and then adds to or reduces the historical amounts based on known upcoming events in the forecast period.[70] However, the Board is concerned about the trends displayed by CW's evidence and finds Attachment 1 to CW-YECL-14 helpful. As noted above, CW evidence is a starting point for further investigation of variance explanations. The Board directs AEY to provide a schedule in future GRAs similar to Attachment 1 to CW-YECL-14, showing labour, fringe and other, comparing actual to approved or forecast levels. The Board also

[69] The content of the preceding three paragraphs was derived from the AEY Reply Argument, paragraphs 36-41.
[70] Transcript Volume 3, page 444, lines 2-25.

directs that the variance explanations provided in Schedule 5.2 be provided at the labour, fringe and other levels for all future GRAs.

125. The Board will now discuss costs at the function level. Changes due to complement levels, vacancy rates, and inflation rates (labour and other) are discussed in earlier sections of this decision and those determinations impact production, distribution, public information and customer accounting function costs.

126. Other[71] costs, as provided in general function costs — in particular, Account 88800 (Maintenance for Company-Owned Houses), Account 88900 (Warehouse and Office Maintenance) — and administration and general function costs — particularly Account 72100 (Administrative) — are discussed in the following paragraphs.

127. **Account 88800 (Maintenance for Company-owned Houses).** "Other" costs were provided in AEY's response to City of Whitehorse's IRs. [72]Variance explanations were provided in Schedule 5.2 of the Application but only for Account 88900 and only for the change from the year 2013 to 2014. The following table shows the actual and forecast "Other" costs for this account:

Table 9. **Account 88800 — Maintenance, Company-Owned Houses — "Other" costs ($000s)**

Account 88800				
2013	**2014**	**2015**	**2016**	**2017**
Actual	Actual	Actual	Forecast	Forecast
18	27	41	54	51

Source: CW-YECL-14(a), Attachment 1, page 3.

128. In YUB-YECL-42, AEY was asked to explain the increases in each of the General Accounts (Accounts 88800 and 88900). AEY provided an explanation for Accounts 88800 and 88900 in aggregate but did not provide an explanation for each account individually. In YUB-YECL-42, AEY did provide an explanation for $32,000, which is the total variance. AEY stated in the Application that, "Ongoing operational and administrative activities are based on historic spending requirements which are then adjusted for known changes in work to be completed in the forecast period."[73] However, the Board finds that $14,000 of the increase from 2015 to 2016 has not been sufficiently explained. In this case, using inflation and a three-year average of costs is duplicative as no specific programs or needs have yet been identified. Therefore, the Board directs that the $14,000 be removed from the 2016 forecast value of "Other" for the aggregate of these accounts (88800 and 88900), with $7,000 being removed from Account 88800 and $7,000 being removed from Account 88900. The revised balance approved by the Board for 2016 "Other" (Account 88800) is $47,000, and the 2017 balance for "Other" (Account 88800) is $44,000. Both balances are subject to changes in the Board-approved inflation rates. AEY is directed to reflect these changes in its compliance filing to this decision.

[71] Other costs do not include the labour and fringe elements as provided in Attachment 1 of CW-YECL-14(a).
[72] CW-YECL-14(a), Attachment 1.
[73] Exhibit BB-1, Application, page 5-3.

129. **Account 88900 (Maintenance, Warehouse and Office)**. "Other" costs were provided in Attachment 1 to CW-YECL-14(a) and variance explanations were provided in Schedule 5.2 of the Application. The following table shows the forecast and actual "Other" costs for this account:

Table 10. **Account 88900 — Maintenance, Warehouse and Office — "Other" costs ($000s)**

Account 88900				
2013	**2014**	**2015**	**2016**	**2017**
Actual	Actual	Actual	Forecast	Forecast
137	156	133	150	153

Source: CW-YECL-14(a), Attachment 1, page 3.

130. In YUB-YECL-42, AEY was asked to explain the increases in each of the General Accounts (Accounts 88800 and 88900). AEY provided an explanation for Accounts 88800 and 88900 in aggregate, but did not provide an explanation for each account individually. In YUB-YECL-42, AEY did provide an explanation for $32,000, which is the total variance. AEY stated in the Application that, "Ongoing operational and administrative activities are based on historic spending requirements which are then adjusted for known changes in work to be completed in the forecast period."[74] However, the Board finds that $14,000 of the increase from 2015 to 2016 has not been sufficiently explained. In this case, using inflation and a three-year average of costs is duplicative as no specific programs or needs have yet been identified. Therefore, the Board directs that the $14,000 be removed from the 2016 forecast value of "Other" for the aggregate of these accounts (88800 and 88900), with $7,000 being removed from Account 88800, and $7,000 being removed from Account 88900. The revised balance approved by the Board for 2016 "Other", (Account 88900) is $143,000, and the approved 2017 balance for "Other" (Account 88900) is $146,000. Both balances are subject to changes in the Board-approved inflation rates. AEY is directed to reflect these changes in its compliance filing to this decision.

131. **Administrative and General function costs.** Schedule 5.2 provided explanations for the labour portions but did not explain the increase in "Other". Except for an explanation related to $21,000 for employee association agreement negotiations.

132. **Account 72100 (Administrative).** "Other" costs were provided in Attachment 1 to CW-YECL-14(a), and variance explanations were provided in Schedule 5.2 of the Application. The following table shows the actual and forecasted "Other" costs for this account:

Table 11. **Account 72100 Administrative — "Other" costs ($000s)**

Account 72100				
2013	**2014**	**2015**	**2016**	**2017**
Actual	Actual	Actual	Forecast	Forecast
1,481	1,541	1,256	1,556	1,585

[74] Application, page 5-3.

Source: CW-YECL-14(a), Attachment 1, page 3.

133. In YUB-YECL-45, AEY was asked to explain the increases in each of the "Admin and General" Accounts (Accounts 72100 through 72900). AEY provided explanations; for Account 72100, the explanation chiefly related to labour costs.

134. The three-year average (2013-2015) for "Other" for Account 72100 is $1,426,000. The Board finds that it is reasonable to use the three-year average for this account. $1,426,000 is the base amount for this account to which inflation is to be applied. Besides inflation, AEY has not provided an explanation for the increase in "Other" costs between 2015 and 2016 and has not justified a different starting base amount for this account. Therefore, starting from the $1,426,000 base amount, the Board has calculated the 2016 forecast value for this account to be $1,455,000. For 2017, the forecast value is $1,483,000. AEY is directed to reflect these changes in its compliance filing to this decision.

6 Taxes Other Than Income

135. Taxes Other Than Income consist of property taxes paid to communities for AEY's office building, generation facilities, substation properties and power lines.

136. The following table summarizes AEY's recently approved, actual and forecasted amounts for property taxes:

Table 12. **Approved, actual and forecast property taxes 2013 to 2017 ($000s)**

	2013	2014	2015	2016 (F)	2017 (F)
Approved	257	265	273		
Actual (A) / Forecast (F)	273	251	256	262	267
Actual (under) or over approved	16	(14)	(17)		

Source: Exhibit BB-1A, 2016-2017 GRA Schedule S1.1, line 10.

137. AEY stated that the increase in actual 2013 property taxes over the approved amount was due to payments made to the Town of Watson Lake.[75] Increases in property taxes that had been forecast for the years 2014 and 2015 did not occur because planned capital work, upon which property tax calculations are in part determined, did not materialize. Therefore, any year-over-year increases in property taxes paid during 2014 and 2015 were due primarily to inflation.

138. AEY has forecasted property taxes in the amount of $0.262 million for the year 2016 and $0.267 million for the year 2017.

139. AEY stated that property tax increases in the amounts of $0.006 million and $0.005 million for 2016 and 2017 respectively are due to inflationary increases applicable to each test year.

[75] Exhibit B-6, YECL Responses to UCG requests, UCG-AEY-28(b), PDF, page 150 of 260.

6.1 Views of interveners

140. In argument, UCG stated that AEY should not be allowed to increase property taxes for the test years due to a lack of evidence, such as the utility's property tax assessments.

6.2 Applicant responses to interveners

141. AEY replied that the position of UCG constituted new evidence that should be struck from the record or be given no weight by the Board.

6.3 Views of the Board

142. The Board considers that it is reasonable for AEY to forecast its 2016-2017 Taxes Other Than Income based on the application of relevant inflation rates by using, as a starting point, its 2015 actual property taxes paid. With respect to the issue of property tax assessments raised in Final Argument, the Board does not have sufficient information on the record of the current proceeding to determine that consideration of property tax assessments is required. If UCG wishes to explore the issue of whether property tax assessments should be provided in support of AEY's Application, it may bring forward this issue for examination in AEY's next GRA.

143. The Board approves AEY's "Taxes Other Than Income" amounts forecasted in the amount of $0.262 million for the year 2016 and $0.267 million for the year 2017, as filed.

7 Depreciation

144. In its Application, AEY forecasted depreciation expense in the amount of $5.792 million for the year 2016 and $6.283 million for the year 2017. This resulted in an increase from 2015 actual expense in the amount of $0.380 million in 2016 and $0.491 million in 2017. AEY explained that the increases were the result of forecasted growth in property, plant and equipment and subject to depreciation expense.

145. AEY stated that the depreciation rates used in the calculations of 2016 and 2017 depreciation expense were developed by way of a technical update, which relied on the depreciation parameters approved by the Board in Board Order 2014-06 for AEY's 2013-2015 GRA. In that application, AEY submitted a full depreciation study in support of the depreciation parameters ultimately approved by the Board. AEY also stated that in 2016 and 2017, it would continue to record the annual amortization of the accumulated depreciation reserve differences credit in the amount of $0.402 million,[76] [77] which was at the same level approved in Board Order 2014-06.

146. The following table summarizes AEY's recently approved, actual and forecast amounts for depreciation expense:

[76] This would have the effect of reducing YECL annual depreciation expense by $0.402 million.
[77] YECL 2016-2017 GRA Schedules, Schedule S7.4, line 50.

Table 13. **Approved, actual and forecast depreciation expense — 2013 to 2017 ($000s)**

	2013	2014	2015	2016 (F)	2017 (F)
Approved	4.520	5.252	5.778		
Actual (A)/Forecast (F)	4.382	4.895	5.412	5.792	6.283
Actual (under) or over approved	(0.138)	(0.357)	(0.366)		

Source: Exhibit 2016-2017 GRA Schedule S1.1, line 11.

147. During the course of this proceeding, three issues were raised with respect to depreciation, each of which is discussed in the sections that follow.

7.1 Technical update to determine updated depreciation rates

7.1.1 Views of interveners

148. There were concerns raised by UCG that AEY had not indicated nor requested approval in its application of the revised depreciation rates used in its calculation of depreciation expense for the test years stemming from the results of a technical update to its previous depreciation study.

149. UCG argued that since actual depreciation expense incurred for the 2013-15 test period had been lower than the amount approved to be recovered through AEY's tariff, this was evidence of an over-recovery of depreciation expense in the amount of $1.1 million[78] over the 2013-15 period.

150. UCG submitted that AEY's request for increases to its depreciation expense should be denied because of these two issues.

7.1.2 Views of the Board

151. The Board observes that there appears to be some confusion by parties pertaining to certain depreciation-related elements. The Board has provided the following general information with respect to the differences between a full depreciation study and a technical update to a depreciation study.

152. Depreciation expense typically encompasses three components of capital cost recovery: (1) the depreciation related to the original cost of the asset; (2) estimations related to net salvage costs (also referred to in this proceeding as future removal and site restoration); and (3) in some circumstances, the amortization of accumulated reserve differences that arise, in part, from changes in depreciation methodologies or depreciation parameters determined during the course of a depreciation study.

153. Periodically, a new depreciation study is conducted and three depreciation "parameters" — consisting of the average service life, the standard "Iowa curve" and dispersion pattern (collectively referred to as the life-curve parameters) and the net salvage percent parameter — are confirmed or revised. The actual accumulated depreciation recorded to date, based on the prior approved depreciation parameters,

[78] UCG Final Argument, PDF page 21 of 40.

can differ from the theoretical amount of accumulated depreciation that would have been recorded for each account using the updated parameters. The resulting difference — termed the accumulated reserve difference or variance — is measured in dollars and may be recovered or refunded through depreciation expense as a stand-alone true-up amount, or may be combined into a depreciation rate that includes the amortization of the accumulated reserve differences true-up amount.

154. During the preparation of full depreciation studies, technical updates are often conducted. The purpose of a technical update (which is less costly to prepare than a depreciation study) is to apply the currently approved depreciation parameters to the recent actual plant balance information provided by the utility in order to develop the most current and relevant depreciation rates for the test years. The most recent plant balances will reflect both plant additions and retirements occurring since the time of the last depreciation study or technical update.

155. To summarize, it is during the course of examining a depreciation study that the depreciation parameters of life-curve, net salvage percentages and the amortization of accumulated reserve differences are approved. The rates that are proposed by the utility are used as an input in depreciation expense calculations and are a direct result of the depreciation parameters being applied to the most recent actual plant-in-service information. During the course of a technical update, approved depreciation parameters are similarly applied to the most recent plant balances for the purposes of updating depreciation rates, which will then be used in depreciation expense calculations.

156. In its 2016-17 GRA, AEY submitted a technical update to its December 31, 2011 depreciation study, which had been submitted as part of the record in the 2013-15 GRA.

157. The technical update undertaken by AEY relied on currently approved life-curve depreciation parameters to determine updated depreciation rates for the 2016 and 2017 test years based on December 31, 2015 plant-in-service balances. The result was a total decrease in depreciation expense of approximately $0.100 million over the test years.[79]

158. In the case of AEY, and consistent with past Board Orders, there is no estimation made for recovery of any future net salvage costs. As a result, there is no depreciation parameter related to or reflective of a net salvage percent that would otherwise form a part of AEY's depreciation rates and therefore depreciation expense.

159. Furthermore, AEY has historically recovered any amortization of accumulated reserve differences as a dollar amount, which is generally determined and approved during the course of examining a depreciation study.

160. With respect to the 2016-17 amortization of accumulated reserve differences amount, AEY stated that it had "… simply continued with what the Board approved as part of the 2013-'15 General Rate Application for amortization of differences…"[80] The

[79] Transcript, Volume 1 page 148.
[80] Transcript, Volume 3, page 424.

result was a credit, or refund, of depreciation expense in the amount of $0.402 million per year.

161. Based on the foregoing, the Board is not convinced by the concerns raised by UCG that there is a need to deny or adjust AEY's depreciation expense calculations due to its December 31, 2015 technical update. Consistent with common depreciation practice, AEY's technical update relied on currently approved life-curve depreciation parameters applied to its most recent plant balances for the purposes of updating its depreciation rates, which were used to inform its 2016-17 depreciation expense calculations. The Board finds there is not an issue with the derivation of AEY's forecast depreciation expense.

162. With respect to UCG's assertion of over-collection of depreciation expense for the years 2013-15, the Board determines the revenue requirement on a prospective basis. Depreciation parameters and the resultant rates are estimates applied to forecasted plant balances to determine forecasted depreciation expense. While the depreciation rates themselves will remain static during the test years, actual plant balances — upon which those rates are applied — may differ from those forecasted by the utility. The end result, as observed by UCG, may be differences between approved and actual depreciation expense.

163. For the purpose of calculating AEY's depreciation expense for 2016 and 2017, any corrections identified by AEY during the course of the proceeding, or directions made elsewhere in this decision, including those with respect to capital additions, are to be incorporated by AEY. AEY is directed to incorporate these changes in its compliance filing to this decision and its final determination of depreciation expense.

7.2 Use of the mid-year convention for calculation of depreciation expense

164. During the oral hearing, Board counsel questioned AEY as to why, in its depreciation expense calculation for Account 493 — Demand Side Management, the mid-year convention had not been applied. The question posed was directed toward a common regulatory convention related to depreciation expense calculations whereby only a half-year of depreciation expense is taken in the year in which an asset has been capitalized into rate base, followed by full-year depreciation expense calculations in subsequent years. This mid-year convention supports that in the absence of having to consider individual and exact dates of capitalization for any given asset, an assumption can be made for depreciation purposes that, on average, all assets are capitalized at the mid-point of the year.

165. An examination of AEY's schedules indicated that depreciation expense had not been taken for any of the amounts on Account 493 — Demand Side Management 2016 capital addition. The amounts had been deferred to the year 2017 where a full year depreciation expense was recorded.

166. AEY witness, James Grattan, advised that if the Board determined that coincident with the capitalization of the asset in 2016 it should attract a half-year of depreciation expense in that same year, he would not be opposed to this calculation.[81]

7.2.1 Views of the Board

167. The Board considers that consistent with AEY's depreciation expense calculations for all other accounts, it is necessary for AEY to incorporate the use of the mid-year convention for Account 493 — Demand Side Management. AEY is directed to revise its depreciation expense calculation for Account 493 — Demand Side Management to reflect a half-year depreciation expense in 2016 for current year capital additions in its compliance filing to this decision.

168. For clarity, the Board confirms AEY's use of a five-year amortization period is acceptable for this depreciation expense calculation, in accordance with the findings in Board Order 2014-06.[82]

7.3 Supporting documentation for the amortization of accumulated depreciation reserve differences

169. During the IR process, AEY confirmed that costs related to net salvage had not been included in the depreciation expense for the years 2013-2017.[83]

170. AEY also confirmed during the oral hearing that despite its Schedule 7.4 — Schedule of Amortization of Differences identified for each account number, negative net salvage in varying percentages, the schedule did not include any costs related to the recovery of net salvage. James Grattan, witness for AEY, stated that Schedule 7.4 "… simply continued with what the Board approved as part of the 2013-'15 General Rate Application for amortization of differences…"[84]

7.3.1 Views of the Board

171. The Board is satisfied that the 2016-2017 depreciation expense calculated by AEY, including the calculation related to its amortization of accumulated depreciation reserve differences, does not include any amounts related to the recovery of net salvage.

172. However, the Board observes that Schedule 7-4, relied on by AEY to support its amortization of accumulated reserve differences amount, disclosed certain negative net salvage percentage information that prompted the clarifications described earlier in this section. The Board considers it would be a simple matter for AEY to have revised Schedule 7-4 to be consistent with the approvals stemming from Board Order 2014-06 and doing so would have avoided unnecessary confusion as to whether the reserve difference amounts complied with Board directions. The Board directs AEY in its future applications, to ensure all supporting schedules filed are consistent with and reflective of Board Orders.

[81] Transcript, Volume 3, page 427.
[82] Board Order 2014-06, Appendix A, page 101..
[83] Exhibit B-6, UCG-AEY-29(a).
[84] Transcript, Volume 3, page 424.

8 Return on rate base

173. AEY included the following information on return on rate base:

Table 14. **Return on rate base — 2013 to 2017 ($000s)**

	2013	2014	2015	2016	2017
	Actual	Actual	Actual	Test Period	
Return on Rate Base	5,550	5,782	5,838	6,945	7,400

Source: Exhibit BB-1, Application, page 8-1.

AEY explained that the growth in rate base is a result of capital additions and an increase in the return on equity (ROE). This resulted in the increase in return on rate base for the forecast period.

8.1 Cost of capital

174. AEY has requested the Board use the British Columbia Utilities Board (BCUC) Generic Cost of Capital (GCOC) proceeding as the benchmark for determining ROE. In addition, AEY is seeking a 60-basis-point risk premium over the BCUC GCOC benchmark to determine its ROE for each of the test years.

8.1.1 Rate of return on capital

175. In response to YUB-YECL-50, AEY cited the BCUC's most recent GCOC decision (G-75-13) but did not provide that decision as requested. In that decision, the benchmark rate was determined to be 8.75 percent.

176. AEY, YEC[85] and John Maissan[86] accepted the BCUC rate. CW did not comment on the rate established by the BCUC. UCG recommended that the Board use the most recent GCOC decision from the AUC.[87]

177. UCG added that given AEY's direct tie to the Alberta market, AEY should not be allowed to link its ROE for the 2016-2017 test period to the recently approved BCUC GCOC benchmark rate of 8.75 percent plus a risk premium of 0.60 percent.

178. YEC disagreed with the UCG position and stated:

> The Board has previously determined that the BCUC model is the precedent for Yukon; as such, in Yukon Energy's view there is no basis for using a different benchmark ROE for the current review.[88]

8.1.2 Applicant responses to interveners

179. AEY submitted that UCG has ignored past decisions of the Board and the clear statements of the Board as they relate to equity ratio and ROE in Board Order 2014-06.

[85] YEC Final Argument, page 3.
[86] JM Final Argument, page 6.
[87] UCG Final Argument, paragraphs 137-150.
[88] YEC Reply Argument, pages 3-4.

8.1.3 Views of the Board

180. In Board Order 2009-02, the Board ruled that the BCUC generic cost of capital (GCOC) model is the most appropriate and is generally accepted by parties.[89]

181. The Board, in Board Order 2009-08 stated:

> The Board continues to be of the view that relying on a generic ROE from a different jurisdiction is the most efficient means of addressing an inherently complex and costly matter. The Board strongly believes that such an approach is the most efficient manner for a jurisdiction such as Yukon.
>
> The Board considers that the BCUC approach has been successfully applied to both utilities under this Board's jurisdiction and has resulted in fair returns to both utilities.
>
> Therefore it is determined that the BCUC approach is a precedent for this jurisdiction and will continue to be the precedent for this jurisdiction until otherwise ordered by this Board.[90]

182. The Board continues to be of the view that the BCUC GCOC model is the most appropriate for Yukon for the reasons set out above. The Board does not agree with the submissions of UCG on this issue as no evidence was filed to persuade the Board to change its approach. Accordingly, the Board finds that AEY is to use the BCUC GCOC benchmark for ROE of 8.75 percent.

8.1.4 Equity premium

183. AEY engaged Concentric Energy Advisors, Inc. (Concentric) to determine whether a risk premium relative to the BCUC GCOC benchmark utility would be appropriate and, if so, what that risk premium should be. The report prepared by Concentric was submitted as Attachment 8.1 to the Application.[91]

184. AEY submitted that it faces greater business risk than the average Canadian or British Columbia benchmark utility and therefore warrants a risk premium. Concentric submitted that the premium should be 60 basis points.[92]

185. Concentric, based on its research, recommended a risk premium of between 40 and 75 basis points in comparison to the BCUC benchmark utility. The range was framed by FortisBC Electric at a 40-basis-point premium and PNG-West (Pacific Northern Gas-West), representing the upper boundary. Concentric chose 60 basis points, as it matched the 9.35-percent ROE awarded to Maritime Electric, a utility Concentric submitted had similar business risk as AEY but had a deemed equity ratio of 40.9 percent.[93]

[89] Board Order 2009-02 Appendix A: Reasons for Decision, page 29.
[90] Board Order 2009-08, paragraphs 280-282.
[91] Exhibit BB-1, Application, page 8-3.
[92] Exhibit BB-1, Application, page 8-4.
[93] Exhibit BB-1, Application, Attachment 8.1, page 6.

186. Concentric added:

> In most respects, the business risk of AEY has not materially changed since 2009 when the Board determined that a risk premium of 46 basis points above the benchmark utility in British Columbia was reasonable. Weak economic conditions in the province, coupled with the impact of energy efficiency and DSM programs, and increased variability in residential usage per customer due to fuel switching, have made it more difficult for AEY to accurately forecast sales;
>
> The business risk profile of AEY is most similar to that of Maritime Electric, which derives a higher percentage of its electricity supply from company owned generation than AEY, but which serves five times more retail customers. Maritime Electric has an authorized ROE of 9.35 percent on 40.9 percent common equity;
>
> The business risk profile of AEY is also similar in many respects to that of Newfoundland Power, except that AEY is substantially smaller in terms of both customers served and rate base. Newfoundland Power has an ROE of 8.80 percent on 45 percent common equity; and
>
> The business risk of AEY is lower than that of PNG-West, which is similar in size but faces more risk than AEY due to the loss of a major customer that caused throughput to decline by 87 percent from 2003-2012. PNG West has an authorized ROE of 9.50 percent (or 75 basis points above the BC benchmark) on 46.5 percent common equity.[94]

187. AEY submitted that the business risks it faces encompass market demand, operational risks, small size and geographic environment and that these risks expose it to a higher degree of business risk compared to the BCUC benchmark utility as well as most utilities located in other areas of Canada.[95]

8.1.4.1 Views of interveners

188. YEC took the position that it is appropriate to use the BCUC benchmark ROE of 8.75 percent as the foundation, and that for Yukon utilities, it is appropriate to "apply a risk premium adder above the benchmark in order to reflect additional risks faced by northern utilities on an isolated grid."[96] However, YEC said that AEY's proposal deviates from the BCUC approach and from past Yukon precedent. AEY's approach maintains a requirement for expert evidence and testimony to determine ROE for Yukon utilities that potentially increases both the cost and complexity of these proceedings.

189. YEC recommended that the Board use the same methodology and justification for determining ROE that was established in the 2005 GRA — that is, a point midway between YEC and FortisBC Electric of 48.5 basis points.[97]

[94] Exhibit BB-1, Application, Attachment 8.1, page 32.
[95] Exhibit BB-1, Application, page 8-3.
[96] YEC Final Argument, page 3.
[97] YEC Final Argument, page 5.

190. In Reply Argument, YEC stated:

> BCUC decisions referenced in the current Board proceedings have confirmed the requirement for a risk premium relative to the approved benchmark for various BC utilities to reflect the relative size of the utility and the characteristics of its service area.[98]

191. YEC later added that in Board Order 2009-02, the Board stated:

> … that when using the BCUC generic cost of capital, a risk premium is required for Yukon utilities.[99]

192. YEC then stated that the bookends for assessing a risk premium against the BCUC benchmark are FortisBC Electric and PNG-West.[100]

193. John Maissan argued that the position that AEY faces increased sales forecast risk due to customers switching home heating sources is speculative. Based on the conclusion of Concentric, the sales forecast risk does not have a material effect on the risk profile for AEY.[101]

194. Mr. Maissan noted that the concern regarding variation in earnings did not appear to hold. He referred to YUB-YECL-63(b), arguing that in spite of significant economic variations and sales variabilities in 2014 and 2015, AEY, with the exception of 2015, has consistently earned above approved ROE levels.[102]

195. Mr. Maissan recommended:

> … that AEY has flexibility in the way it manages its costs such that it fairly consistently over-earns its approved ROE, and therefor [sic] is not subject to nearly as much risk as it tries to make out it is. In my view a fair ROE is the BCUC Benchmark of 8.75% and any risk premium is more that adequately covered by its equity thickness of 40% as compared to BCUC's 38.5%.[103]

196. CW noted that Concentric concluded that, "In most respects, the business risk of AEY has not materially changed since 2009…"[104] CW submitted that the request for a risk premium was unwarranted.[105]

197. UCG argued that the appropriate benchmark should be based on the latest AUC GCOC proceeding and therefore did not make any recommendation with respect to an equity premium.[106]

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[98] YEC Reply Argument, page 4.
[99] Board Order 2009-02, Appendix A: Reasons for Decision, page 29.
[100] YEC Reply Argument, page 5.
[101] JM Final Argument, page 5.
[102] JM Final Argument, page 6.
[103] JM Final Argument, page 6.
[104] Exhibit BB-1, Application, Attachment 8.1 (Concentric Report), page 31. Concentric did subsequently state that "the most important change has been uncertainty; and unpredictability associated with usage per customer, especially among the residential class".
[105] CW Final Argument, paragraph 26.
[106] UCG Final Argument, paragraphs 137-150.

8.1.4.2 Applicant responses to interveners

198. AEY challenged CW's interpretation that the Board, in Board Order 2014-06, ruled that a risk premium was not necessary or that there was no incremental business risk. Rather, AEY submitted that the Board ruled that the determination of whether a risk premium should be applied was not clear, and the Board directed AEY to provide justification in its next GRA.[107]

199. AEY contended that Mr. Maissan's position that the Board only use the BCUC benchmark ignores the evidence that FortisBC Energy has lower business risk than AEY.[108]

200. In response to YEC argument, AEY said the approach it took was in response to a direction from Board Order 2014-06. Further, AEY disagreed with the submission of YEC that AEY's business risks have not changed, noting that AEY's usage per customer has made it more difficult to accurately forecast sales.[109]

201. For risk due to small size, Concentric stated:

> Given the extremely small size of AEY, Concentric considers that to be the most important risk factor for purposes of establishing an appropriate risk premium for AEY. In order to select a comparator group that was reasonably risk comparable, Concentric thought it was important to select smaller investor owned electric and gas distribution companies. Other regulators have accepted the importance of small size in setting the risk premium for regulated utilities. For example, the BCUC's Stage 2 Generic Cost of Capital decision states that small size relative to the benchmark utility was a factor in awarding FortisBC Electric a risk premium of 40 basis points (at page iv), that FortisBC Whistler was awarded an additional 25 basis points (for a total of 75 basis points above the benchmark) "in recognition of risks related to its small size" (at page iii), and that PNG-Tumbler Ridge was awarded an additional 25 basis points above the 50 basis point risk premium given to PNG-West due to "greater weight on factors related to size" among other things (at page iv).[110]

8.1.4.3 Views of the Board

202. The Board made its determinations with respect to an ROE risk premium in Board Order 2009-02 and 2009-08 as follows:

> *Should a risk premium be applied?*
>
> In Appendix A to Board Order 2005-12, the Board accepted YEC's recommendation of a risk premium of 52 basis points and noted that it was greater than the risk premium for FortisBC and less than the risk premium for Pacific Northern Gas. YEC argued that it was more risky than FortisBC since FortisBC had inter-tie connections with other utilities allowing more purchase power options and affording greater flexibility to its generation.

[107] AEY Reply Argument, paragraphs 57-63.
[108] AEY Reply Argument, paragraphs 64-66.
[109] AEY Reply Argument paragraphs 77 and 80.
[110] Exhibit B-9, YUB-YECL-62(a).

> The evidence in the Foster Report, although related to capital structure, also suggested a risk premium for YECL. The Board accepts that when using the BCUC generic cost of capital, a risk premium is required for Yukon utilities.
>
> *What risk premium should be applied to YECL?*
>
> In its reply argument, YECL suggested a risk premium of 52 basis points, the same as YEC. However, the Board notes that YECL acknowledges that relative to YECL, YEC has more risk. The Board considered Appendix A of Board Order 2005-12 in finding that without the same inter-tie connections as FortisBC, YECL is more risky than FortisBC. As a result, the Board finds it reasonable to place the risk premium for YECL at the midpoint of the risk premiums between YEC and FortisBC — at 46 basis points. Therefore YECL is directed to use an ROE for 2008 of 9.08%. For 2009, YECL will use a risk premium of 46 basis points above the BCUC 2009 benchmark ROE.[111] *(footnotes omitted)*

203. The Board continues to maintain this view. For this Application, as in past GRA decisions, the Board does not have a recent YEC decision to determine one of the bookends for the risk premium range and to use to calculate an ROE premium as it did for Board Order 2009-02.

204. The Board notes that Concentric concluded that AEY's business risks have not materially changed since 2009.[112] Further, Concentric stated that weak economic conditions in Yukon, coupled with the impact of energy efficiency and DSM programs, as well as increased variability in residential usage per customer due to fuel switching, have made it more difficult for AEY to accurately forecast sales.

205. However, although forecasting sales volume may be more difficult, the table in the preamble to YUB-YECL-52 shows that AEY's actual sales — with the exception of one major growth year (2012) — are consistently within two percent of the previous year's levels. Further, Concentric concluded that sales forecast risk due to changing heating fuel sources does not have a material effect on the risk profile of AEY.[113]

206. Additionally, AEY testified:

> That we, as a utility, should be able to do come up with a forecast that's somewhat accurate to what our actual sales are going to be. It's changing and there's lot of challenges. You've got weather. You've got all the new demand side management programs, including micro-grid generation. There's lots to it. But I think it should be something that is expected that we should be able to take a guess at. Better than a guess. We should be able to do a thorough analysis and come up with a reliable forecast...[114] I would just add that we did know the existence or lack of existence of a weather-normalization account for ATCO Electric, but we didn't frame it as an adder to the risk premium per se.[115]

[111] Appendix A to Board Order 2009-02: Reasons for Decision, page 29 of 49.
[112] Exhibit BB-1, Application, Attachment 8.1, page 29.
[113] Exhibit BB-1, Application, Attachment 8.1, page 27.
[114] Transcript Volume 1, page 86, lines 2-13.
[115] Transcript Volume 1, page 87, lines 9-12.

207. Based on AEY testimony, sales volume risk is a risk AEY can manage and, in the Board's view, it is a risk that does not attract a risk premium. However, through the submissions of YEC and AEY and the comparisons with FortisBC Energy (the BCUC benchmark utility), the Board is persuaded that AEY can be eligible for a risk premium relative to the BCUC benchmark utility to mitigate risks other than those related to sales volume. The following paragraphs discuss the Board's determination of the appropriate level of the risk premium.

208. The Concentric report made the following comparisons:

> The 2016 Generic Cost of Capital proceeding is currently underway in British Columbia and a decision is expected by July 2016. The benchmark utility, FortisBC Energy, has lower business risk than AEY. FortisBC Energy is substantially larger than AEY, both in terms of retail customers served and regulated rate base. FortisBC Energy serves 56X more retail customers and its rate base is 33X larger than AEY's. FortisBC Energy also has more cost recovery protection through deferral and variance accounts and more revenue stability through a weather normalization clause than AEY. As a gas distributor, FortisBC Energy owns its regulated gas distribution system, whereas AEY owns the electric distribution system and some generation facilities. As discussed in more detail later in the report, investors and credit rating agencies view companies that own generation as higher risk than pure transmission and/or distribution utilities. FortisBC Energy has an allowed ROE of 8.75 percent on 38.5 percent common equity, while AEY currently has the same ROE and a slightly higher equity ratio of 40 percent…[116] FortisBC Electric was awarded an ROE risk premium of 40 basis points above the benchmark utility by the BCUC in the GCOC Stage 2 proceeding. Like AEY, FortisBC Electric has 40 percent deemed common equity. FortisBC Electric is almost 10X larger than AEY in terms of retail customers served and has rate base about 15X greater than AEY. FortisBC Electric supplies approximately 45 percent of its load through company-owned generation, while AEY supplies about 9 percent, indicating that FortisBC Electric has relatively more generation risk.[117]

209. "Section IV — Risk Assessment" of the Concentric report listed the following risks:

- small size,
- generation risk,
- fuel and purchased power risk,
- volume/demand risk,
- regulatory environment,
- deferral/variance accounts, and
- competition from alternative fuels.[118]

210. The Board considers the two greatest risks to be size and generation. Discussion of the remaining listed risks follows. Fuel and purchased power are addressed through

[116] Exhibit BB-1, Application, Attachment 8.1, pages 4-5.
[117] Exhibit BB-1, Application, Attachment 8.1, page 5.
[118] Exhibit BB-1, Application, Attachment 8.1, page 1.

deferral accounts. AEY has stated its preference to manage volume/demand risk. Regarding regulatory environment, Concentric has stated that traditional cost of service regulation is generally considered less risky than incentive regulation.[119] AEY is under cost-of-service regulation, while FortisBC Energy and FortisBC Electric are under incentive regulation. Concentric did conclude that AEY was at higher risk than other companies due to not having a variance account for weather-related volume risk. As AEY prefers to manage its sales volume risk, the Board does not accept Concentric's conclusion that AEY faces increased regulatory risk because it does not have a weather-related volume risk deferral account. The Board's view is that AEY faces less regulatory risk than FortisBC Energy and FortisBC Electric because it is under cost-of-service regulation. Additionally, Concentric did not state that AEY deserved a risk premium for variance/deferral accounts.[120] Regarding competition for alternative fuels, Concentric submitted that FortisBC Energy faced competition from electric heat among residential customers and to a lesser extent than did PNG-West. However, Concentric concluded that this type of risk was difficult to quantify and likely does not have a material effect on the risk profile of AEY.[121]

211. Based on the foregoing, the Board concludes that in determining relative risk for AEY, the Board should look at size and generation risk.

212. For the comparators provided by Concentric,[122] the Board does not accept the use of FortisBC Electric for the lower boundary. Although FortisBC Electric is larger than AEY, its generation assets are a quantum level higher than the generation assets of AEY. Concentric referenced the BCUC GCOC Stage 2 proceeding[123] and the awarding of a 40-basis-point risk premium to FortisBC Electric. Part of the determination of the risk premium for FortisBC Electric was:

> The evidence supports the findings that FBC [FortisBC Electric] faces additional price competitiveness risk as compared to the Benchmark and in addition there is some additional risk related to small size. The Panel finds no substantial difference in supply risk as compared to the Benchmark, and, regarding operating risks, we found there was no basis on which to establish the potential impact of any differential in risk.[124]

213. Price competitiveness was a major factor in determining the risk premium for FortisBC Electric. Concentric concluded that competitiveness (from alternate supply) did not have a material impact on the risk profile of AEY. Generation assets for FortisBC Electric are materially higher than for AEY. Similarly, the generation assets for Maritime Electric are materially higher than those of AEY. Maritime Electric procures its power from a different jurisdiction.[125] Due to these factors (competitiveness, relative amount of generation assets), the Board finds that AEY is not directly comparable to FortisBC

[119] Exhibit BB-1, Application, Attachment 8.1, page 25.
[120] Exhibit BB-1, Application, Attachment 8.1, page 26.
[121] Exhibit BB-1, Application, Attachment 8.1, pages 26-27.
[122] FortisBC Electric for the lower boundary, PNG-West for the upper boundary, and settling on an ROE equivalent to Maritime Electric.
[123] Exhibit BB-1, Application, Attachment 8.1, page 5. The reference was to BCUC Generic Cost of Capital Proceeding (Stage 2) Decision, March 25, 2014 at page 113.
[124] Exhibit BB-1 BCUC Generic Cost of Capital Proceeding Stage 2 Decision, Order G47-14, March 25, 2014, page 86 (public document available at www.ordersdecisions.bcuc.com)
[125] Exhibit BB-1, Application, Attachment 8.1, page 21. The Board views cross-jurisdictional transactions as facing higher regulatory risk than those transactions occurring within a single jurisdiction.

Electric or Maritime Electric. Accordingly, the Board does not find generation to be a significant risk for AEY in relation to the risk of Fortis BC.

214. Further, in terms of comparisons to Maritime Electric, the Board notes that its ROE was determined through a settlement agreement. There is no evidence on the record of this proceeding indicating the trade-offs that may have occurred during the negotiation process or how the ROE level was determined. As a result, the Board gives little weight to the ROE determined by way of a settlement agreement.

215. Concentric stated that PNG-West was larger than AEY and added that PNG-West was awarded a higher risk from the BCUC due to customer growth, market demand and throughput risk (due to the loss of a major customer, which caused total system throughput to decline by 87 percent from 2003-2012). Concentric referenced the BCUC GCOC Stage 2 decision for this information. These circumstances do not apply for AEY. Therefore, the Board concludes that AEY is not directly comparable to PNG-West.

216. Although earnings variability has been mentioned by Concentric, the Board also notes that AEY has been able to consistently meet or exceed forecast earnings levels.[126]

217. The Board took note of Concentric's view that the extremely small size of AEY is an important risk factor for the purposes of establishing an appropriate risk premium for AEY.[127]

218. Based on the evidence, the Board has determined that small size is the most significant factor to be considered in determining a risk premium for AEY.

219. The evidence on this record shows that BCUC has set a premium for a small size utility at 25 basis points.[128] This Board accepts that a 25-basis-point premium over the BCUC benchmark utility is reasonable for this jurisdiction.

220. Further, as AEY will have an equity thickness[129] greater than that of the BCUC benchmark utility, the Board is of the view that this will compensate AEY for the other differences between it and the benchmark utility.

221. Therefore, the Board approves an ROE of 9.00 percent for AEY for both test years. AEY is to reflect this change in its compliance filing to this decision.

8.1.5 Common equity ratio

222. AEY requests to maintain the previously approved common equity ratio of 40 percent for each of the test years of 2016 and 2017.

223. John Maissan supported AEY's request for an equity thickness of 40 percent.[130]

[126] Exhibit B-9, YUB-YECL-63(b).
[127] Exhibit BB-1, Application, Attachment 8.1, pages 19-20.
[128] Exhibit B-9, YUB-YECL-62(a).
[129] Equity thickness refers to the ratio of debt to equity of a utility.
[130] JM Final Argument, page 6.

224. UCG submitted:

> … that linking AEY's return on equity to cost of capital formulas developed in other jurisdictions will reduce regulatory costs but should also warrant a review of equity thickness of AEY's capital structure. UCG submits that AEY's equity thickness should be reduced to 37% to match the level established by the Alberta Utilities Commission for its benchmark utility.[131]

8.1.5.1 Views of the Board

225. In Board Order 2014-06, the Board states:

> In terms of equity thickness, this Board has not relied upon the results of generic proceedings from other jurisdictions. Although past references have been acknowledged regarding other North of 60 utilities, the Board has used utilities within Yukon in its decision-making. In this proceeding, YECL has stated that its business risks are somewhat less than those of YEC. YECL has also stated that its business risks for this application are largely consistent with those assessed in its 2008-09 Application… Further, although YECL has provided examples of jurisdictions where higher equity thicknesses have been granted the benchmark utility in the BCUC GCOC proceeding was awarded an equity thickness of 38.5 percent. The Board considers that the equity thickness presented for the NWT jurisdiction or for the BCUC GCOC benchmark utility is not comparable to YECL. Therefore, the Board allows YECL to continue to have an equity thickness that is equal to that awarded to YEC — that is, 40 percent — and directs YECL to reflect such in its compliance filing. Further, as YECL has stated that its business risks are consistent with those in its 2008-09 GRA application, the Board is satisfied that maintaining the same equity thickness it has allowed in YECL's 2008-09 GRA is fair and reasonable.[132]

226. The Board continues to view that an equity thickness of 40 percent for AEY is reasonable for the reasons set out above. No evidence was presented in this proceeding in support of another approach. The Board does not accept the submissions of UCG on this issue because no evidence was presented in support of these submissions or the use of an Alberta utility as a comparator in the current proceeding. The Board finds that AEY is to maintain an equity thickness of 40 percent.

8.1.6 Cost of debt

227. AEY discussed its forecast for long-term debt rates in the Application.[133] AEY used an average long Canada bond rate and applied a spread to determine the forecast debenture rate. The following was provided by AEY:

Table 15. **Forecast long-term debt rates**

	2016	**2017**
Long Canada Bond Rate	1.90% - 2.70%	2.30% - 3.30%
Credit Spread	1.80% - 2.20%	1.80% - 2.20%
Debenture Rate	3.70% - 4.90%	4.10% - 5.50%

[131] UCG Final Argument, paragraph 136.
[132] Board Order 2014-06, Appendix A: Reasons for Decision, page 54.
[133] Exhibit BB-1, Application, pages 8-4 to 8-5.

Recommended Rate	4.30%	4.80%
Issue Costs	0.05%	0.05%
Recommended All-in Rate	4.35%	4.85%

Source: Exhibit BB-1, Application, page 8-5.

228. AEY updated its cost of debt numbers in its October 24, 2016 update. The all-in rates were revised to 3.77 percent for 2016 and 4.07 percent for 2017.

8.1.6.1 Views of interveners

229. CW argued that AEY's cost of new debt has a pattern of over-forecasting, and noted that in 2014, the cost of debt was 0.96 percentage points lower than forecasted and for 2015, new debt was 1.08 percentage points lower than forecasted. CW further stated that AEY was protected in 2013 when actual cost was higher than forecasted, as actual cost was determined and approved by the Board for that year.[134]

230. John Maissan argued that for the years 2008-2015, the actual rates for cost of debt were never above the approved rates for cost of debt, but were usually below the approved rates. Mr. Maissan referenced the response to JM-AEY-14 in support of this argument and recommended a cost of debt rate of 4.35 percent for both test years.[135]

231. UCG, based on Board Order 2013-01, recommended that the Board adopt a historic formulaic approach of 120 basis points for forecasting future debt costs.[136]

8.1.6.2 Applicant responses to interveners

232. AEY argued that CW's evidence in relation to a pattern of over-forecasting debt rates should be ignored because AEY actually under-forecasted the rate for cost of debt in one of the years used by CW. AEY added that its October 24, 2016 update to the rate for cost of debt exceeded the recommended reduction in debt rates recommended by CW.[137]

233. AEY submitted that the UCG recommendation that the historical formulaic approach for determining rates for cost of debt should be used for AEY should be rejected due to lack of evidentiary support.[138]

8.1.6.3 Views of the Board

234. The Board notes that AEY did update its cost of debt in its October 24, 2016 update and that update was in response to YUB-YECL-73. The Board also notes that in Argument and Reply Argument, none of the interveners commented on the update to cost of debt.

235. The Board has reviewed the submissions on cost of debt. Originally, AEY forecasted the long Canada bond rate to be 2.50 percent for 2016 and 3.0 percent for

[134] CW Final Argument, paragraph 33.
[135] JM Final Argument, page 4.
[136] UCG Final Argument, paragraphs 152-154.
[137] AEY Final Argument, paragraphs 98-99.
[138] AEY Reply Argument, paragraph 81.

2017. In its update, AEY revised those long Canada bond rates to 1.92 percent for 2016 and 2.22 percent for 2017. It appears that AEY has maintained a credit spread of 1.8 percent.

236. The Board is persuaded by the submissions of Mr. Maissan that the AEY response to JM-AEY-14 show that actual costs of debt are never above and are consistently below forecast levels. For this reason, the Board rejects AEY's forecast for 2016 cost of debt.

237. However, in reviewing the AEY response to YUB-YECL-73, the Board notes that actual issue dates for bonds in the years 2011 to 2015 generally occurred before November[139] of the year of issuance. Given that 2016 bonds have been issued before the release of this decision, the Board directs AEY to use the actual cost of debt for 2016 and to reflect this change in its compliance filing to this decision.

238. Further, in YUB-YECL-73(b), AEY was asked to provide the sources for the long Canada bond rate and credit spreads. Although AEY did provide sources, AEY did not explain the manner in which it determined its credit spreads.

239. In response to YUB-YECL-73(a), AEY provided its historical long Canada bond rates and credit spreads for the years 2011-2015. For that period, the average credit spread was approximately 1.6 percent.

240. As the Board cannot ascertain how AEY determined its credit spread of 1.80 percent, the Board will use the average of credit spreads for the 2011-2016 period. AEY is directed in its compliance filing to this decision to provide an updated table similar to that provided in response to YUB-YECL-73(a) and to update that table to include 2016 actual numbers. In addition, AEY is directed to use the average of the credit spreads for the years 2011-2016, each year given equal weighting, to calculate the credit spread for 2017. The calculated credit spread for 2017 will be added to the updated long Canada bond rate of 2.22 percent and the issue costs of 0.05 percent to determine the cost of debt for 2017.The Board accepts the revised long Canada bond rate proposed by AEY for 2017. AEY is directed to reflect these changes in its compliance filing to this decision.

8.2 No Cost Capital

241. AEY discussed No Cost Capital (NCC) in its Application. It stated that NCC related to the balances for deferred pensions including Other Post Employment Benefit (OPEB) plans and the Reserve for Injuries and Damages (RID).

242. OPEB plans are administered on a combined basis with Canadian Utilities Limited and AEY is assessed a percentage of its payroll at a rate calculated for the plan as a whole. AEY continues to use the cash basis for its pension plan and the OPEB plan. The OPEB plan covers such items as drug, health and dental costs for retirees.

[139] 2012 is the only year where the issuance was after November 1. The issuance date for that year was November 14.

243. The RID is as an account used for uninsured and uninsurable losses and the deductible portion of insurance claims. Attachments 8.2 (Beaver Creek House Fuel Spill — $109,700) and 8.3 (Fish Lake #1 Spillway Failure — $100,000) to the Application provided details of the two incidents that have been included in the RID account.

244. The following continuity schedule for NCC was provided by AEY:

Table 16. **Continuity for NCC Mid-Year Balance — 2013 to 2017 ($000s)**

	2013	2014	2015	2016	2017
	Actual	Actual	Actual	Test Period	
Total No Cost Capital	165	(24)	446	660	667

Source: October 24, 2016 Update, Schedule S8.4.

8.2.1 Views of the Board

245. The Board finds AEY's updated NCC costs to be reasonable and approves the updated amounts, subject to any impacts from other sections of this decision.

9 Capital additions

246. AEY submitted that capital additions were primarily driven by the requirement to upgrade, enhance and replace components on the distribution and generation systems that have reached the end of their lifecycle, as well as meet system needs due to load growth. AEY's actual and forecasted capital expenditures and additions to rate base for the period from 2013 to 2017 are shown in the following table:

Table 17. **AEY Capital Expenditures and Additions – 2013 to 2017 ($000s)**

	Actuals			Forecasts	
	2013	2014	2015	2016	2017
Generation	5,574	8,599	3,060	6,630	5,316
Distribution	7,268	6,236	6,232	7,659	8,994
General Property & Equipment	2,516	2,002	1,402	759	1,008
Capital expenditures total	15,358	16,837	10,694	15,048	15,318
Capital additions to rate base	14,321	18,849	10,252	14,234	14,907

Source: Application, Page 9-1; Application, Schedule 9.1.

247. Using the numbers in the above table, the capital expenditures for the test period are forecasted to increase by approximately 40 percent each year when compared to 2015. Capital additions to rate base for 2016 and 2017 are forecasted to increase by 39 and 45 percent respectively, when compared to 2015.

248. Generally, with the exception of projects described in the following sections, AEY's capital additions are categorized as generation, new extensions, distribution improvements, street and sentinel lights, meters and general property and equipment. Generic descriptions of each category are provided in pages 9-1 to 9-5 of the Application, while a listing of the projects that make up the dollars shown Table 17

(above) of this order are provided in Schedules 9.1 and 9.2 of the Application. A listing of the capital expenditure information for 2016 and 2017, as well as project descriptions for those projects greater than $100,000, are found in Attachment 9.1 and Attachment 9.2, respectively. Full business cases for major capital projects, $500,000 or greater, are included in the Application's appendices.

249. AEY provided the following information that shows that its controllable capital was within 3.2 percent the capital expenditure amounts approved in Board Order 2014-06 for its 2013-2015 GRA. The following table shows the variances in AEY's controllable capital expenditures between its actual and approved amounts for 2013-2015:

Table 18. **Controllable Capital Expenditures — 2013 to 2015 ($000s)**

2013-2015 GRA			
	Actual	**Approved**	**Variance (%)**
New Extensions	6,141	15,480	60.3%
Contributions	(4,866)	(13,039)	62.7%
Net New Extensions	1,275	2,441	47.7%
"Controllable" Capital	36,748	37,955	3.2 %
Total Net Capital	38,023	40,396	5.9%

Source: Exhibit B-4, CW-YECL-1.

9.1 Views of interveners

250. Mr. Maissan pointed out that the projects listed in Attachments 11-1 to 11-6 of the Application,[140] relating to project cost overruns, exceeded the forecast budgets by a total of $4.7 million. The 2013 to 2015 forecast controllable project expenditures spent is $32.048 million. Mr. Maissan stated that AEY underspent by $5.947 million or by 15.65 percent of the original forecast. Mr. Maissan went on to state:

> … a significant number of forecasted capital projects did not get done, had they been done the "controllable" capital budget would have been exceeded by $4.7 million or more. Many projects have been dropped or deferred, but AEY provided no information on them.[141]

251. Mr. Maissan recommended that the Board order AEY to provide detailed information on capital projects that have been deferred or dropped, and the level of detail should be commensurate with the detail required for AEY capital forecasts. Mr. Maissan further recommended that the Board reduce the controllable capital budget, after any and all other adjustments, by three percent. The Board should further order AEY to indicate in a compliance filing where these cuts were made.[142]

[140] Exhibit BB-1, Application, Project Completion Summaries Table, page 11-3.
[141] JM Final Argument, page 7.
[142] JM Final Argument, page 7.

9.2 Applicant responses to interveners

252. Responding to Mr. Maissan's submission, AEY referred to its response to YUB-YECL-11(b) Attachment 1, a spreadsheet that includes a list of all projects approved capital projects and deemed capital projects from the 2013-2015 period. AEY pointed out that in this spreadsheet, projects with variances of 10 percent and greater than $50,000 are accompanied by a corresponding explanation. AEY noted that in its Application it had resubmitted updated business cases for significant projects that were previously approved in the 2013-2015 GRA, but have been deferred to the 2016-2017 test period.[143]

253. AEY stated that the arbitrary reduction of the capital forecast, as recommended by Mr. Maissan, ignores the significant amount of evidence on the record supporting the need and prudence of the capital projects within the capital forecast, pointing out that the capital program throughout 2013-2015 was significantly higher than what AEY has experienced in recent years. AEY submitted that it has incorporated the learnings gained from this experience into its capital forecast by making adjustments in its forecasting methodology and assumptions. AEY submits that the evidence on record does not support Mr. Maissan's recommended reduction.

9.3 Views of the Board

254. The Board has reviewed AEY's capital addition forecasts and corresponding information and considers that AEY has provided sufficient support for its capital forecast for 2016-2017. Although the increase in capital additions to rate base for 2016 and 2017 are forecasted to increase by 39 and 45 percent respectively from 2015, the capital additions are reasonable when compared to the prior three years' actual capital additions. Subject to the Board's findings in the subsections that follow, the forecast capital additions and capital expenditures have been supported by business cases and the Board accepts the explanations in the updated business cases for significant projects that were previously approved in the 2013-2015 GRA, but were deferred.

255. For these reasons, Mr. Maissan's recommendation for a general cut for AEY's controllable capital budget is not warranted.

9.4 Distribution Plant additions

256. AEY provided the following information related to distribution plant additions for the period 2013 to 2017:

Table 19. **Distribution Plant Additions — 2013 to 2017 ($000s)**

	Actual	Approved	Actual	Approved	Actual	Approved	Forecast	
	2013	2013	2014	2014	2015	2015	2016	2017
New Extensions	2,350	5,033	1,693	5,147	2,098	5,300	2,160	3,388
Distribution Improvements	4,002	4,021	3,980	4,457	3,326	3,875	4,346	4,178
Street & Sentinel Lights	536	420	322	945	466	813	585	1,132
Meters	308	600	166	204	234	207	200	204

[143] AEY Reply Argument, paragraph 96.

Transformers & Regulators	72	10	75	10	108	10	368	92
Distribution in Total	7,268	10,084	6,236	10,762	6,232	10,205	7,659	8,994

Source: AEY Application, Schedule 9.1.

257. AEY pointed out that, as a result of AEY's forecasting, the 2016 forecasts represent a 41-percent reduction compared to the 2015 approved forecast.[144]

9.4.1 Views of interveners

258. UCG noted that total actual distribution plant additions for the 2013 to 2015 timeframe were $19.736 million, compared to the approved forecast amount of $31.051 million. UCG submitted that ratepayers have paid the costs of $11.315 million in forecasted distribution plant additions that never took place within the test years.

259. Given this recent track record of overestimating plant additions, UCG recommended that the distribution plant forecast for the 2016-2017 test period be reduced by 40 percent.[145]

9.4.2 Views of the Board

260. Regarding the UCG comments that forecasted capital additions were greater than actual capital additions, the Board notes that the approved forecasted plant additions ($31.051 million) for 2013 to 2015 have been subsequently trued up to now reflect the actual plant additions ($19.736 million) for 2013 to 2015. It is the actual plant additions that are now reflected in the 2015 actual closing balances that are used to inform the 2016 test year opening capital balances. Furthermore, this is standard process for forward-looking (or prospective) cost-of-service jurisdictions.

261. The Board has reviewed AEY's forecasted planned additions to distribution and corresponding information and considers that AEY has provided sufficient support for its distribution plant additions for 2016-2017. With respect to AEY's test year distribution forecasts compared to previous year's actual and approved numbers, it appears that the primary reason for the increase is related to distribution improvements. The Board's findings related to distribution improvements are addressed in section 9.4.4. Subject to the findings in that section, the Board considers AEY forecasts to be reasonable for distribution plant additions and does not agree with UCG's recommendation to reduce the 2016-2017 test-period forecasts.

9.4.3 New Extensions

262. With respect to New Extensions, AEY stated that the forecast is based on discussions with the Yukon government, the City of Whitehorse and First Nation governments. AEY holds a seat on the Development Review Committee with the City of Whitehorse. As a result, AEY has contact with developers and engineering firms, which informs the new extension forecast. AEY submitted that it also considers historical customer additions in formulating its forecasts to specifically account for walk-in customers who may require service during the test years.

[144] AEY Reply Argument, paragraph 126.
[145] UCG Final Argument, paragraphs 175 to 176.

263. AEY submitted that the reason for lower new extensions expenditures as compared to previously approved numbers is slower economic growth than previously anticipated. AEY added that new extensions are a capital cost not at the control of AEY and are dependent on development within the communities in which the company operates.[146]

264. AEY submitted that it uses the best information available when preparing its forecasts, which includes any lessons learned from past test periods. AEY reiterated that its new extension forecast is based on "historical actual experience and incorporated information from the Yukon Government, the City of Whitehorse, and First Nation Governments … there is no systemic forecast error and … the forecast has no relation to, or correlation with the 2013-2015 forecast."[147]

9.4.3.1 Views of interveners

265. CW noted that AEY admitted it over-forecasted capital additions related to new extensions over the 2013 to 2015 period. Furthermore, taking customer contributions into account, the forecast for net new extensions over the period is 47.7 percent higher than actuals. CW submitted that the systematic over-forecasting results in customers paying for capital that is not actually put into service. Accordingly, CW recommended the Board reduce the 2016-2017 test period forecast for net new extensions by 47.7 percent to account for the systemic forecast error.[148]

9.4.3.2 Views of the Board

266. With respect to the argument put forth by CW, the Board is not convinced that a three-year period of actuals being lower than approved amounts can be classified as systemic. The Board accepts Mr. Tenney's testimony on behalf of AEY that overall, the three-year forecast period was fairly accurate.[149] However, the Board notes that might not be true on a line-item-by-line-item basis. Mr. Tenney also stated in testimony:

> With the exception that there are capital projects that are customer driven and with our obligation to serve, we think those are a given that the need to move forward.[150]

267. Mr. Massie added:

> And just speaking specifically to the capital program and specifically to new extensions here, we have realized that, you know, we missed the mark in new extensions for that test period. I'd say that we've reflected it in our '16 and '17 forecasts.[151]

268. The Board accepts AEY's testimony that it has adjusted its test period forecasts to account for historical over forecasting. The Board does not accept CW's and UCG's recommendations to reduce AEY's new extension forecast.

[146] Exhibit B-4, CW-YECL-1.
[147] AEY Final Argument, paragraph 130.
[148] Exhibit C3-3, CW Evidence, A8.
[149] Transcript, Volume 3, page 441, lines 13 to 14.
[150] Transcript, Volume 3, page 442, lines 6 to 9.
[151] Transcript, Volume 3, page 442, lines 17 to 22.

269. Furthermore, the Board notes that the 2016 new extension forecast is three percent greater than 2015 actuals, and the 2017 forecast is 2.2 percent greater than the 2016 forecast, after the Whistle Bend Stage 3 project is accounted for in the forecast.

270. In the Board's view, AEY is taking into account current economic conditions in the Yukon and information available to it at the time of preparing the forecast. Moreover, the Board notes that AEY's submission that indicated that year-to-date costs for new extensions, as of October 31, 2016, are $2.116 million, or 98 percent of the 2016 forecast.[152]

271. For these reasons, the Board approves AEY's forecast as filed.

9.4.4 Distribution improvement projects

272. AEY submitted that distribution improvement projects generally fall into four major categories: (1) system performance projects, (2) life extension projects, (3) system replacement projects, and (4) "forced" projects. AEY clarified that these projects are required to maintain system performance at an acceptable level and that this category of capital projects includes system protection, voltage, current and line clearance projects.[153] AEY added that it tracks distribution system performance on an ongoing basis and the performance is reviewed when preparing the capital forecast.[154]

273. AEY submitted that the proposed test period forecast distribution improvement projects are prudent in that they ensure the continued supply of safe and reliable electricity to AEY's customers at a reasonable price. Accordingly, AEY submitted that the Board should approve the 2016-2017 distribution improvements as applied for.[155]

274. AEY pointed out that it files KPI (key performance indicators) reports on an annual basis. AEY submitted that the reports are available on the Board's website and added that that the last such report for year 2015 was filed on May 4, 2016.[156]

9.4.4.1 Views of interveners

275. UCG noted that system improvement expenditures increased an average of $3.75 million per year over the period from 2010 to 2015. UCG further noted that AEY proposed system improvement expenditures of $4.346 and $4.178 million in 2016 and 2017 respectively, but has provided no evidence of expected system performance improvements with respect to line losses and interruption indices. UCG included the following in argument:

> UCG submits that without an established benchmark, the Board and ratepayers cannot determine how well AEY is actually performing with respect to SAIFI (System Average Interruption Frequency Index), SAIDI (System Average Interruption Duration Index) and CAIDI (Customer Average Interruption Duration Index) reliability performance indices. UCG submits that the Board

[152] AEY Reply Argument, paragraph 91; Transcript, Volume 3, page 509, line 25, to 510, lines 1-2.
[153] Exhibit BB-1, Application, Page 9-2.
[154] Exhibit BB-1, Application, Page 9-3,
[155] AEY Final Argument, paragraph 138.
[156] AEY Reply Argument, paragraph 46.

> should establish performance and reliability benchmarks and AEY should be directed to report its actual performance against these benchmarks.[157]

276. Considering the above, UCG submitted that AEY should be denied distribution expenditures in 2016 and 2017 since evidence has not been provided that demonstrates a benefit to customers.

9.4.4.2 Views of the Board

277. The Board approves AEY's proposed distribution improvement expenditures as filed. Nonetheless, with respect to system performance projects, the Board notes AEY submission that it:

> … tracks distribution system performance on an ongoing basis and the performance is reviewed when preparing the capital forecast. To this end, AEY reviews unplanned outages that may be attributed to system deficiencies, prepares a report for each, and implements corrective action.[158]

278. Considering the above and AEY's submission that it files KPI reports on an annual basis, the Board directs AEY to file on the record of its next GRA, the KPI reports that have been filed with the Board after the record closed in this proceeding. The Board further directs AEY, in its next GRA, to include with the list of improvement projects the reasons for the system deficiency — supported by the KPI filings — that form the basis of the project and the resulting costs. Moreover, AEY is directed to provide a sample report referred to in the quotation above in its next GRA, and to point out and clarify the project expectations — i.e. the expected system performance improvement(s) — that AEY expects will be affirmed by future KPI filings.

9.4.5 Meters

279. AEY submitted that capital additions for meters should include new meter installations that are required to replace end-of-life meters consistent with Measurement Canada requirements. This category of capital additions also includes the installation of new meters required to accommodate load growth associated with customer requests for service. The capital meter additions forecast is based on known areas of development and expected connection repairs.

280. AEY pointed out that it purchases meters from ATCO Electric at cost and, in so doing, is able to take advantage of the economies of scale realized by ATCO Electric in its meter purchases. This is a significant benefit to AEY and its customers. AEY submitted "this is undoubtedly the least cost alternative given that it is able to purchase its meters, but with the buying power of a utility the size of ATCO Electric."[159] Furthermore, other than AEY and its customers benefiting from this relationship, AEY submitted that it is unclear as to what benefit could be derived by the ATCO family of companies, given that the meters are purchased at cost.

[157] UCG Final Argument, paragraph 231.
[158] AEY Final Argument, paragraph 136.
[159] AEY Reply Argument, paragraph 136.

9.4.5.1 Views of interveners

281. With respect to meter replacement and new installations, UCG commented that over the period 2013-2015, AEY had actual expenditures of $708,000 that were well below the approved $1 million total. UCG submitted that this significant over-forecasting trend should be used to reduce the forecasts proposed for 2016 and 2017. UCG also referred to AEY's submission that it purchases meters from ATCO Electric's meter shop in Grande Prairie. UCG submitted that there should be further clarification on how this arrangement was determined to be the least cost alternative supply point and whether the affiliate relationship had been used to provide benefits to the ATCO family of companies.[160]

9.4.5.2 Views of the Board

282. The Board accepts AEY's submission that it is able to purchase its meters at cost from ATCO Electric. Accordingly, the Board finds that no further information is required. The meters are supplied by the affiliate at cost, and the mere existence of the affiliate arrangement for the provision of these meters, in these circumstances, does not merit further clarification by AEY at this time. UCG's request is denied.

9.5 Conversion of existing LED streetlights

283. AEY indicated that it has been in discussions with its customers, some of which are municipalities, regarding recent developments related to the conversion of existing streetlights to light-emitting diode (LED) lamps. Considering there is capital outlay associated with the conversion of existing streetlights to LED, AEY submitted that it is seeking the Board's direction

> … as to the appropriate method of accounting for the capital costs associated with customers requesting conversions of existing streetlights to LED. ATCO Electric Yukon considers there to be two available options:
>
> (1) A full customer contribution required for all associated capital costs; or
>
> (2) All capital costs associated with requested conversions would be a system cost, not subject to a customer contribution.[161]

284. AEY explained that the rationale for this project being a system cost would be that the initial streetlight cost was contributed by the customer when the streetlight was originally installed. At the end of useful life when the asset needs replacement, the customer is not required to contribute again and the cost becomes a system cost.[162]

285. AEY acknowledged the benefit of reducing load on the electrical system and that the longer lifespan of equipment used under this project could lead to reduced costs in operation and maintenance of the lights. AEY submitted that converting all existing high-pressure sodium (HPS) streetlights to LED streetlights in AEY's communities would cost approximately $2 million and the project would need to be completed over several years due to resource constraints.

[160] UCG Final Argument, paragraphs 221 to 222.
[161] Exhibit BB-1, Application, page 9-3.
[162] Exhibit B-9, YUB-YECL-10(c).

286. AEY provided two cost-benefit analyses for converting lights in thermal communities and hydro communities for each of the two options: customer contributions or system costs.[163] The cost-benefit analyses showed that a greater net present value (NPV) would result if the conversions were done in diesel-served (thermal) communities compared to hydro communities. AEY reiterated that it is not applying for approval of a wholesale replacement of all existing HPS streetlights but is seeking Board direction as to the appropriate method of accounting for the costs associated with customer conversions of existing streetlights to LED.[164]

9.5.1 Views of interveners

287. Mr. Maissan indicated his support for the LED-conversion project and recommended that the Board direct AEY to proceed with the conversion of streetlights (i.e. HPS to LED lights) as a system cost and that priority be given to diesel-served communities.

288. CW indicated its support for the conversion of existing streetlights to LED lamps. However, CW submitted that it is inappropriate for AEY to request the Board to issue direction as to the method of accounting for the associated capital costs in the absence of a fully supported proposal by AEY on that issue. Accordingly, CW recommended that the Board direct AEY to submit a proposal, supported by evidence, which can be tested by the Board in order for it to make a determination on this issue.

9.5.2 Applicant responses to interveners

289. AEY submitted that it is not clear as to what additional information CW is proposing that AEY file with the Board. From AEY's perspective, the decision is relatively straightforward in that either the conversion costs are treated as a system cost or the local municipality must pay for the conversion cost as a contribution in aid of construction. AEY pointed out that economic analyses of both treatments as well as the total estimated costs involved are on the record. All parties have had an opportunity to submit IRs and cross-examine AEY with respect to the information. AEY submitted that the record is complete and the Board has ample information to render a decision on the treatment of costs for streetlight conversions.

> Moreover, the treatment of such costs will likely inform the decisions of the relevant communities and/or municipalities with regard to such conversions.[165]

290. AEY asserted that requiring it to come forward with a fully supported proposal is entirely unnecessary and would only serve to add inefficiencies to the regulatory process.

9.5.3 Views of the Board

291. The Board supports AEY's rationale for a streetlight project to be treated as a system cost, as outlined:

[163] Exhibit B-9, YUB-YECL-10(b) Attachment 1.
[164] Exhibit B-4, CW-YECL-27 (h).
[165] AEY Reply Argument, paragraph 95.

> … the initial light asset cost was contributed by the customer when the light was originally installed in accordance with the approved Terms and Conditions of Service at the time. At the end of useful life when the asset needs replacement the customer is not required to contribute again and the cost becomes a system cost.[166]

292. Accordingly, the Board directs that all capital costs associated with the end-of-life streetlight conversions be treated as a system cost.

293. With respect to LED streetlight installations that are not end-of-life conversions, the Board directs AEY to treat the costs related to new installations or requested conversions as capital costs that attract a full customer contribution in aid of construction.

9.6 Project cost overruns (related to Direction 13 — Board Order 2014-06)

294. Responding to Direction No. 13 of Board Order 2014-06, in relation to project cost overruns, AEY included project completion summaries for all projects that were forecast in AEY's 2013-2015 GRA for which actual costs were 100 percent and $100,000 greater than the original forecast. AEY's compliance with Direction 13 is discussed in section 11 of this decision.

295. The following table contains the list of projects and the related attachment in section 11 of the Application wherein the project descriptions and summaries are provided. Actual and approved forecast costs are included in the summaries, as well as explanations for the variances:

Table 20. **Project Completion Summaries ($000s)**

Project	Attachment	Approved Forecast	Actuals
Fish Lake Dyke Upgrade	Attachment 11.1	1,720	2,552
Old Crow Plant Expansion	Attachment 11.2	1,950	4,566
Beaver Creek PLC Upgrade	Attachment 11.3	180	377
McIntyre Subdivision Rebuild	Attachment 11.4	725	1,453
Deep Creek Subdivision Connection	Attachment 11.5	60	213
Old Crow Staff Accommodations	Attachment 11.6	100	274

Source: Exhibit BB-1, Page 11-3, Attachments 11.1 to 11.6.

[166] Exhibit B-9, YUB-YECL-10(c)

296. AEY provided business cases for projects where the actual costs were in excess of $100,000 and for which no business case was provided. The following table includes the list of projects and the actual costs:

Table 21. **Business Cases for Completed Projects ($000s)**

Project	Attachment	Actuals
Old Crow #2 Replacement	Attachment 11.7	161
Whistle Bend Subdivision Stages 1 & 2	Attachment 11.8	513
Whistle Bend Underground Residential Service	Attachment 11.9	116
City of Whitehorse Range Road Widening	Attachment 11.10	188
4L314 Chilkoot Way Upgrade	Attachment 11.11	483
Azure Road Extension	Attachment 11.12	151
2nd Ave Rebuild	Attachment 11.13	115

Source: Exhibit BB-1, Page 11-4, Attachments 11.7 to 11.13.

9.6.1 Views of interveners

297. With respect to the Old Crow plant expansion project, which went over-budget by $2.616 million, Mr. Maissan asserted that AEY has been operating in Old Crow for many years and submitted that AEY should have suspended and re-assessed the project when it ran into design cost overruns and local logistical difficulties. Mr. Maissan recommended that the Board retain experts to review and audit the project execution process and cost, or the Board disallow $1 million of the $2,616 million cost overruns and remove it from rate base.[167] With respect to the Old Crow Unit 4 Addition project, Mr. Maissan recommended that the Board direct AEY to provide a business case for this project, as it was completed $112,000 over budget.[168]

298. UCG expressed concerns with the significant expenditures over approved budget amounts for many of the capital projects that had been previously approved. UCG submitted, “If there is no evidence that these extra costs were prudently incurred, they should not be allowed to be added to AEY’s rate base.”[169] UCG stated that additions to AEY’s rate base should be limited to allowed cost estimates unless AEY can provide evidence that the cost overruns were prudently incurred. In particular, UCG submitted that the doubling of the cost for the McIntyre Subdivision Rebuild should be the responsibility of AEY, not ratepayers. It concluded with respect to the McIntyre Subdivision Rebuild:

> AEY’s evidence is that this project went well beyond the Board approved level because the location and installation of the existing underground system would be in constant conflict with the installation of the new system. This along with other issues resulted in a requirement to develop an entirely new project scope. This resulted in AEY incurring an additional $728,000 in costs (for a project originally assumed to cost $725,000) and doubling the cost of the project.[170]

[167] JM Final Argument, page 8.
[168] JM Final Argument, page 9.
[169] UCG Final Argument, paragraph 160.
[170] UCG Final Argument, paragraphs 177.

299. UCG further submitted that AEY should not be able to arbitrarily add capital projects to rate base that have not been previously approved by the Board. [171] Furthermore, expressing concerns respecting the rapid increase in AEY's rate base in the 2013-2015 timeframe, UCG submitted that AEY should be required to submit detailed asset management plans and/or distribution system plans, the elements of which "will drive the development of investment and maintenance for the test year(s) and beyond.[172]

9.6.2 Applicant responses to interveners

300. Notwithstanding the comprehensiveness of the Old Crow business case, as acknowledged by Mr. Maissan, AEY submitted that project timing was restricted given the timing of the construction of the ice road. Furthermore, the magnitude and extent of the many challenges that arose could not have been foreseen. AEY submitted that although the business and community need did not change, AEY proceeded with the project knowing the costs would be fully examined in a future GRA. AEY confirmed that it would be:

> … submitting a Post Completion Summary of the project, that clearly indicates the variances, and gives the Board and Interveners an opportunity to examine the Project during the entirety of a regulatory proceeding is the most appropriate process, without putting the supply of power to the community at risk.[173]

301. Respecting Mr. Maissan's recommendation that AEY submit a business case for the Old Crow Unit 4 addition costs because project costs exceeded the original estimate by more than $100,000, AEY pointed out that the costs did not exceed 100 percent of the approved forecast. As such, AEY submitted "the business case type description of the cost overrun sought by Maissan is not required" and AEY submitted that there is sufficient information on the record to deem the project useful and prudent.[174]

302. Responding to UCG, AEY replied that it does not arbitrarily add capital projects to rate base. AEY's capital expenditure forecasts are based on the best available information at the time of its GRA. AEY submitted that unknown costs that arise and are not included in test period forecasts are subsequently included as actuals in future applications, thus providing the Board and interveners with the opportunity to assess the need and prudency of such costs. AEY submitted that despite UCG's claims, there is ample evidence on the record to demonstrate that all costs related to McIntyre Stage 1 have been prudently incurred. AEY argued that project planning was comprehensive and many assumptions were validated. It could not have predicted what caused the project scope to be adjusted. AEY indicated that, "Project planning and execution was constantly reviewed and updated with the best available information, al while ensuring the customer and Project needs are addressed."[175]

[171] UCG Final Argument, paragraph 162
[172] UCG Final Argument, paragraph 165
[173] AEY Reply Argument, paragraph 104.
[174] AEY Final Argument, paragraph 106.
[175] AEY Reply Argument, paragraph 129.

303. AEY added that there is no evidence on the record indicating that the "capital projects put forward by AEY are not needed or that they have not been completed prudently."[176] With respect to the UCG submission that AEY provide a detailed asset management plan, AEY submitted that such an undertaking is beyond the scope of this proceeding and is being put forward by UCG with limited explanation and no evidence to justify such a request.[177]

9.6.3 Views of the Board

304. The Board notes that in its Application, AEY has provided:

(a) project completion summaries that were forecast in its 2013-2015 GRA, for which actual costs were 100-percent and $100,000 greater than the original forecast; and

(b) business cases for projects where actual costs were greater than $100,000 and for which no business cases were provided.

305. As a result, AEY provided a business case (Appendix 11) for the Destruction Bay Unit 3 replacement where actual costs exceeded the $450,000 forecasted by $184,000. The Board further acknowledges that AEY provided a comparison of forecast and actual costs,[178] accompanied with an explanation for projects with variances of 10 percent and greater than $50,000.

306. When costs are provided in a GRA on a forecast basis, the Board accepts the information available at the time of filing the Application or that becomes available prior to the close of record of the proceeding. Providing the Board with the best available information at the time that it must make its decision assists the Board in determining a revenue requirement for the utility that most closely matches a utility's expected costs given facts known at the time the application was made or before the close of record. It is incumbent on the utility to do so, and for the utility to plan and budget in preparing its forecasts. Unforeseen projects may arise after a Board Order is issued with respect to the forecast test period. In these cases, the Board reviews the project costs and the variances in the subsequent GRA to ensure that the costs were prudently incurred by the utility.

307. Despite the magnitude of some of the variances between forecast and actual capital expenditures for certain capital projects, the Board accepts the variance explanations provided by AEY.

308. Considering the above, the Board accepts the information found in the project completion summaries and business cases for completed projects. No further direction from the Board is required. The projects and their corresponding costs are discussed in the following sections.

[176] AEY Final Argument, paragraph 122.
[177] AEY Reply Argument, paragraph 125.
[178] Exhibit B-9, YUB-YECL-11(b) Attachment 1.

9.7 Major capital projects

309. In the Application, AEY provided 11 business cases found in Appendix 1 to Appendix 11, in support of major capital projects where forecast costs were $500,000 or greater. Major capital projects and the underlying business cases are discussed in the sections below.

9.7.1 Fish Lake System expenditures[179]

310. AEY noted that the Fish Lake hydro system was built around 1950 and the aging infrastructure is coming to the end of its useful life. In order to maintain Inflow Design Flood (IDF) rates and comply with its water licence for Fish Lake, AEY proposed two projects: the Fish Lake Ditch 3 Diversion project and Fish Lake #2 Head Pond Spillway replacement.

9.7.1.1 Fish Lake Ditch 3 Diversion project (Appendix 1)

311. This project was previously approved in AEY's 2013-2015 GRA. On May 31, 2013, AEY was granted a 25-year extension to its water-use licence, HY12-065. AEY submitted that during the water licence application process, it was identified that the Fish Lake Ditch 3 diversion structure and spillway were not adequately built to withstand a 100-year flood event, which is required to meet IDF rates and comply with its water licensing requirements. AEY is planning to replace and upgrade the Ditch 3 diversion structure and spillway to an engineered design that will allow it to meet these requirements. Accordingly, AEY provided an updated cost forecast with respect to this project, which is reproduced below:

Table 22. **Fish Lake Ditch 3 Diversion – 2013 to 2017 — actual and forecast costs ($000s)**

Year	Actuals	Forecasts	Total
2013	16	-	16
2014	51	-	51
2015	67	-	67
2016	-	2,915	2,915
Total	134	2,915	3,049

Source: Exhibit BB-1, Application, Appendix 1, page 2.

9.7.1.2 Fish Lake #2 Head Pond Spillway Replacement (Appendix 2)

312. Investigative repairs of the Fish Lake #2 head pond spillway structure identified that the overall structure was in need of replacement. AEY explained that it will have to replace the existing spillway structure in order to adequately handle IDF flows while maintaining safe access to AEY generation facilities. AEY submitted that the project was designed in 2016 and construction is expected to be completed in 2017. Design and engineering costs are estimated to be $20,000 and the current construction costs are forecasted to be $593,000.

[179] Exhibit BB-1, Application: Appendix 1, Fish Lake Ditch 3 Diversion Replacement and Appendix 2, Fish Lake 2 Head Pond Spillway Replacement.

9.7.1.3 Views of interveners

313. UCG noted that over the period from 2006 to 2015, AEY has spent $11.429 million in capital and $1.96 million in O&M expenditures, while AEY, over the same period, has recovered $5.87 million in revenue requirement from ratepayers. UCG pointed out that AEY is now looking to spend over $3 million on the Fish Lake Ditch 3 replacement project and an additional $0.593 million on the Fish Lake #2 Head Pond Spillway replacement project. Considering the limited amount of total load that is supplied via the Fish Lake plant, it is questionable whether spending this level of funds on a deteriorating plant is providing ratepayers value for their money.[180]

9.7.1.4 Applicant responses to interveners

314. AEY submitted that the projects were being completed on water management structures that direct and control water and water flows in the Fish Lake system in compliance with AEY's water licence. AEY specified with respect to water licensing requirements that:

> As indicated in the Water License, there are maximum and minimum flows that must be maintained throughout the system. Also, a condition of AEY's Water License is that works associated with the License will be maintained to a sound engineering standard (condition 27 of the Water License).[181]

315. AEY further clarified by stating that the specific recommendations for these projects can be found in its *2014 Dam Safety Report*.[182]

9.7.1.5 Views of the Board

316. The Board accepts the need for both of these projects, as they are a condition of the water licence.

317. In the case of the Fish Lake Ditch 3 diversion project, a higher standard in regard to water licence HY12-065 was directed for this project. The change in standard caused a delay as draft designs and spillway channel brushing were required in 2014, additional surveying was necessary to enable updated design models and adjustments in 2015, and further construction and civil work was scheduled to be completed in 2016.

318. The requirement for the Fish Lake #2 Head Pond Spillway Project was not discovered until repairs in 2013 brought to light a sinkhole near this dam structure. Further, investigative work resulting in the 2014 Dam Safety Report recommended replacement of the structure by the end of 2017. Accordingly, the Board does not accept UCG's recommendation to deny the expenditures for this project.

319. The Board accepts the updated forecast costs for the Fish Lake Ditch 3 diversion project as these costs are necessary to meet the standards of the new water licence. The Fish Lake #2 Head Pond Spillway costs have not been challenged in this proceeding, and for the reasons provided in this decision, the Board finds these costs are reasonable.

[180] UCG Final Argument, paragraphs 218 to 220.
[181] AEY Reply Argument, paragraph 134.
[182] Exhibit B-9, YUB-YECL-14(a), Attachment 1.

9.7.2 Watson Lake Bi-Fuel Project (Appendix 3)

320. AEY is proposing a two-phased, three-year project to convert each of its six diesel generation engines in Watson Lake to bi-fuel. The two phases were described as:

- Phase 1: 2016 – 2017: Source Liquefied Natural Gas (LNG) storage equipment; upgrade Watson Lake plant to meet the safety standard for LNG equipment; install Bi-Fuel technology to one of the six engines; and conduct environmental assessment of engines as directed by Yukon Environmental and Socio-economic Assessment Board (YESAB).

- Phase 2: 2018: Source and install Bi-Fuel technology to the remaining five diesel engines at the Watson Lake plant and increase the volume of LNG storage onsite.[183]

321. If Board approval of the project is received in Q1 of 2017, AEY added that Phase 1 could be completed as early as Q3 of 2017. AEY submitted that Phase 2 of the project is expected to be completed following Yukon Environmental and Societal Assessment Board (YESAB) approval of Phase 1.[184]

322. AEY submitted that this project achieves the federal and Yukon governments' goals of displacing diesel and managing electricity costs by using LNG as an alternative fuel source. Using LNG will reduce diesel consumption of its power generation plant in Watson Lake by approximately 50 percent because it is a cheaper fuel source than diesel. AEY asserted that it "… expects to save hundreds of thousands of dollars annually on fuel costs by the end of this project" and that "These savings would be passed directly on to customers."[185]

323. AEY pointed out that forecasted cost savings are dependent on the differential between the price of delivered diesel and LNG to Watson Lake and the consumption of those fuels. AEY added that the bulk of the delivered LNG price is attributed to the cost of liquefaction and transportation fees. Recognizing the uncertainty as to the future prices for diesel and natural gas, AEY provided 20-year NPV analyses using 12 different scenarios where fuel prices were escalated at differing fixed rates from the 2015 historical price of diesel and natural gas.[186]

324. AEY estimated the total cost of this project to be approximately $5 million, albeit at this time, AEY is seeking approval for $3.3 million to implement Phase 1 of the project. AEY submitted that it will competitively tender each of the major elements of the project,[187] excluding the equipment purchased from ATCO Gas. Further:

> ATCO Electric Yukon proposes to purchase the LNG vaporization skid and LNG storage tank that was previously designed and constructed specifically for

[183] Exhibit BB-1, Application, Appendix 3, Watson Lake bi-fuel project, page 1.
[184] AEY Final Argument, paragraph 150.
[185] Exhibit BB-1, Application, Appendix 3, Watson Lake bi-fuel project, page 1.
[186] Exhibit BB-1, Application, Appendix 3, Watson Lake bi-fuel project, Table 2, page 7, and Table 3, page 8.
[187] The major elements of the project are described in the Application, Appendix 3, page 3.

> Watson Lake. This component along with the overall system design is proposed to be purchased by ATCO Electric Yukon at net book value from ATCO Gas.[188]

325. AEY estimates the annual incremental O&M costs that are not included in the 2016-2017 forecasted costs but will apply in future years to be approximately $50,000 per year. AEY submitted that the O&M contract specific to the LNG equipment will be competitively tendered, will include periodic maintenance, and will involve additional safety training for AEY's operational staff.[189]

326. Asked why it would choose a new unit that requires field modifications to burn both diesel and natural gas rather than purchasing a new unit that is factory capable of burning both fuels, and with nameplate performance ratings, AEY responded:

> Until AEY receives YUB approval for the Watson Lake Bi-Fuel project, AEY wants to minimize the funds committed to this project. At the time AEY tenders the Watson Lake Unit 2 Replacement, requests will be made for both diesel and Bi-Fuel enabled generating units. AEY will determine what unit is most prudent to purchase. Once the Watson Lake Bi-Fuel project is complete, factory enabled dual fuel units will be considered as generating units are due for replacement.[190]

327. AEY submitted that all of the project-related costs presented in the following table are budgetary, except for the actual costs incurred to date:

Table 23. **Watson Lake bi-fuel project — Phase 1 and 2 capital costs**

	Phase 1			Phase 2
	2012-15	**2016**	**2017**	**2018**
Study costs	$222,000			
Engineering, design, and permitting	$272,000	$55,000	$152,000	$105,000
LNG vaporizer and LNG storage tank			$1,194,000	
Installation (civil, mechanical, and electrical) and boarding			$1,090,000	
Conversion of remaining units to bi-fuel				$700,000
Tank expansion, piping, cryopump and installation				$905,000
Phase sub-total			$2,985,000	$1,710,000
Total				$4,695,000

Source: Exhibit B-9, YUB-YECL-13(b).

328. AEY submitted that it believes there are environmental benefits to this project, which it has previously discussed and which have further been the subject of a review pursuant to the *Yukon Environmental and Socio-economic Assessment Act.* A decision document that supported the project was issued in August 2013.[191]

[188] Exhibit BB-1, Application, Appendix 3, Watson Lake bi-fuel project, page 3.
[189] Exhibit B-9, YUB-YECL-13(e).
[190] Exhibit B-9, YUB-YECL-24(h).
[191] AEY Final Argument, paragraph 143.

329. With respect to project expenditures, AEY submitted that Phase 1 expenditures are the only costs to be incurred within the test period and AEY is seeking to recover those as part of this GRA. AEY explained that Phase 2 of this project is necessary to provide all of the benefits to ratepayers and reduce costs over the long-term by increasing consumption of LNG over the life of the project. AEY submitted that the objective in this GRA is "to obtain Board approval to complete both phases of this Project and AEY will bring forth Phase 2 costs for a prudency determination as part of a future general rate application."[192]

9.7.2.1 Views of interveners

330. With respect to the results of the analysis provided by AEY in its business case[193] and the fuel price scenarios for diesel and natural gas over the period from 2017 to 2037, Mr. Maissan referred to the following:

> Of the 12 scenarios provided in tables 2 and 3, 2 have a negative 20 year NPVs and 3 are below $2 million in NPV. Four scenarios are at $5 million NPV or higher.[194]

331. Mr. Maissan pointed out that the analysis did not account for renewable generation and assumed that all electrical loads will be served by diesel or LNG for the next 20 years. Noting Mr. Tenney's acknowledgement of this on behalf of AEY, Mr. Maissan pointed out that the Yukon's Independent Power Producers (IPP) policy provides for 2,100 MWh of generation to be available to Watson Lake under the standing offer program portion of the IPP policy. Mr. Maissan submitted that any further generation added under the micro-generation program will displace more diesel generation and weaken the economics of the bi-fuel conversion project.[195]

332. Mr. Maissan noted AEY's submission that the project will break even over 20 years when the price per litre of LNG on a diesel-litre-equivalent basis (DLE) is 75.6 percent of the cost of delivered diesel. Considering the price of LNG over the past 12 months, Mr. Maissan argued that the project is uneconomical if LNG were sourced from FortisBC and is just economical if LNG is sourced from AltaGas in Alberta. Mr. Maissan suggested that in his view, there was a high likelihood that the price differential between natural gas and diesel would approach historic levels (i.e. natural gas prices growing closer to diesel prices). If this were to occur, it would make the project uneconomical regardless of which supplier is liquefying and transporting the natural gas.[196]

333. Considering the above, Mr. Maissan recommended that the Board deny the Watson Lake bi-fuel project. Mr. Maissan further recommended that of AEY's project-related costs to date, approximately $549,000 ($494,000 + $55,000) be amortized over a five-year period. On a related matter, Mr. Maissan suggested that the

[192] AEY Final Argument, paragraph 154.
[193] Exhibit BB-1, Application, Appendix 3, Table 3, page 8.
[194] JM Final Argument, page 12.
[195] JM Final Argument, page 13.
[196] JM Final Argument, page 14.

Board direct AEY to "… channel its off-diesel efforts into the acquisition of local renewable energy sources, including the issuance of an RFP for renewable energy."[197]

334. Should the Board accept AEY's proposed Watson Lake bi-fuel project, UCG submitted that the associated Watson Lake study costs be rolled into capital costs of that project and recovered over the life of the Watson Lake bi-fuel project.[198]

335. YCS recommended that all project-related costs not be allowed into rate base. YCS argued that the project is not economically prudent nor is the project environmentally prudent. YCS submitted that AEY has not made a case for how this project would help governments meet goals to eliminate or reduce the dependence on diesel in indigenous, remote and northern communities with renewable, clean energy as submitted in its GRA filing. YCS also submitted that the project would not help Watson Lake integrate any new renewable energy, but would effectively act as a "barrier to the development of renewables because of the current natural gas prices setting the predicted benchmark cost per kilowatt hour at an unrealistic and unsustainable low."[199]

336. With respect to AEY's claim that the project would result in cost savings for ratepayers, YCS described the claim as dubious and echoed Mr. Maissan's submission, stating the following:

> … the Watson Lake LNG Bi-fuel project is already marginal even with the current fossil fuel prices. Depending on the fuel source, the project is already uneconomic from one supplier. Any shift toward the historical trend (LNG and diesel closer in cost) will make this project uneconomic regardless of which supplier is liquefying and transporting the natural gas.[200]

337. Additionally, YCS submitted that the AEY analysis did not consider the impacts of renewable energy inputs onto the Watson Lake grid within the project lifetime, did not calculate how that would reduce utilization of this project and, by extension, negatively affect the economics and business case. Therefore, considering that the project is not environmentally or economically prudent, the financial risk to the ratepayer from fuel price changes, and the addition of renewable energy to the Watson Lake grid, YCS recommended that the Board deny the Watson Lake bi-fuel project.[201]

9.7.2.2 Applicant responses to interveners

338. Noting that Mr. Maissan and YCS criticized the project business case for not considering the impact of renewables, AEY submitted that it "must make decisions based on the best information it has available to it and there is no evidence of any IPP program developers proposing renewable energy projects in Watson Lake."[202] Given the restriction on nameplate capacity, AEY pointed out that it would take three separate projects to meet the limit of 2,100 MWh/year. Notwithstanding, in order to demonstrate the economic viability of the Watson Lake bi-fuel project, AEY submitted that it re-ran its

[197] JM Final Argument, page 14.
[198] UCG Final Argument, paragraph 172.
[199] YCS Final Argument, page 9.
[200] YCS Final Argument, page 4.
[201] YCS Final Argument, page 5.
[202] AEY Reply Argument, paragraph 141.

model,[203] assuming the availability of 2,100 MWh/year of renewable generation, as of January 1, 2020. AEY submitted that "… there still remains a positive NPV in all six scenarios using AltaGas pricing and three of the six scenarios using the Fortis pricing."[204] Moreover, AEY stated that there is a positive 20-year internal rate of return in all 12 scenarios. AEY added the models were predicated on only two suppliers of LNG, but it is entirely reasonable to expect additional suppliers to come on-line in the near term.

339. AEY pointed out that the current economic evaluation included in the NPVs set out in Table 2 and Table 3 of Appendix 3, and later updated in response to YUB-YECL-13(b), do not include the impact of any Yukon territorial or federal carbon tax.[205] However, should a carbon tax be imposed, AEY submitted that it would likely favour the use of natural gas for electricity generation, the effect of which would be that the NPV of the bi-fuel would increase.[206]

340. AEY submitted that there is no evidence to support any of the statements that YCS made regarding the environmental impacts or lack thereof of the Watson Lake bi-fuel project. AEY further submitted that the Yukon Environmental and Socio-economic Assessment Board heard and considered the environmental evidence in relation to this project and has approved Phase 1.

9.7.2.3 Views of the Board

341. In Board Order 2014-06, the Board stated with respect to this project:

> The Board considers of note YECL's submission that "this is a first-of-its-kind project, a pilot project that we're doing in a phased approach to prove on one unit at Watson Lake over a one-year period." The Board also has taken into account YECL's response that this "is a first-of-its-kind project, to be proven through demonstration on a single unit before proceeding to conversion of the remaining units while ensuring that a reliable supply of natural gas is available and the performance of the entire facility is acceptable."[207] (*footnotes omitted*)

342. In Board Order 2014-06, the Board had also denied the project due to concerns regarding fair market value of certain equipment to be leased from ATCO Gas. On page 82 of that decision, the Board found that fair market value of the lease of equipment assets was best determined through a competitive tender process.

343. In this Application AEY proposed:

> … to purchase the LNG vaporization skid and LNG storage tank that was previously designed and constructed specifically for Watson Lake. This component along with the overall system design is proposed to be purchased by ATCO Electric Yukon at net book value from ATCO Gas.[208]

[203] The model is embedded in the table provided in response to UCG-AEY-53(d), Attachment 1 (Exhibit B-9).
[204] AEY Reply Argument, paragraph 144.
[205] Exhibit BB-1, Application, Appendix 3, Page 5.
[206] AEY Reply Argument, paragraph 146.
[207] Board Order 2014-06 – Appendix A: Reasons for Decision, Page 81.
[208] Exhibit BB-1, Application, Appendix 3, page 3.

344. The Board acknowledges that AEY indicated that the Watson Lake Phase 1 and Phase 2 bi-fuel projects were submitted to address the Board's concerns.

345. AEY provided the information related to a comparison of potential suppliers and fuel price forecasts, as well as alternative fuel-escalation scenarios. A compiled table of this information is below:

Table 24. **Comparison of potential suppliers and fuel price forecasts**

	Supplier	Simple Payback (years)	20-year NPV ($M)	Supplier	Simple Payback (years)	20-year NPV ($M)
Sproule price forecast	Fortis	12	0.4	Fortis	11	0.6
	AltaGas	10	2.1	AltaGas	9	2.4
Both Commodities escalate at 5%	Fortis	11	2.7	Fortis	11	3.0
	AltaGas	9	5.6	AltaGas	9	5.9
Scenario 3: both commodities escalated at 2.5%	Fortis	15	(0.9)	Fortis	15	(0.7)
	AltaGas	11	1.7	AltaGas	10	2.0
Scenario 4: diesel escalated at 5%; natural gas at 2.5%	Fortis	11	3.5	Fortis	11	3.7
	AltaGas	9	6.1	AltaGas	9	6.4
Scenario 5: diesel escalated at 2.5%; natural gas at 5%	Fortis	17	(1.7)	Fortis	16	(1.4)
	AltaGas	11	1.2	AltaGas	11	1.5
Scenario 6: both commodities doubled	Fortis	7	7.1	Fortis	6	7.4
	AltaGas	5	10.2	AltaGas	5	10.5

Source: Exhibit BB-1, Appendix 3: Table 2, Page 7; Table 3, Page 8. Source: Exhibit B-9, response to YUB-YECL-13(b), Page 3 of 6.

346. With respect to Table 24, the Board notes that of the 12 original scenarios provided by AEY, two scenarios have negative-20-year NPVs, three scenarios have NPVs below $2 million, and four scenarios have NPVs of $5 million or higher. AEY provided a further 12 scenarios wherein it accounted for the decrease in costs related to the LNG vaporizer and the LNG storage tank. The table shows that the project economics improved only marginally under the additional 12 scenarios examined.

347. Further, when AEY re-ran the model assuming a scenario of 2,100 MWh/year of renewable generation as of January 1, 2020, the generation from the bi-fuel engines was reduced. However, three (instead of two) of the six scenarios using Fortis pricing were negative.[209]

348. That being said, the Board agrees with Mr. Maissan's concern that the economic comparison provided by AEY with respect to diesel and LNG in Watson Lake must sufficiently take into account potential fluctuations in the delivery costs[210] for these fuels.

[209] AEY Reply Argument, paragraph 144.
[210] Delivery costs include the costs of liquefaction and transportation of LNG.

Mr. Maissan pointed out that the liquefaction and transportation of LNG is a higher percentage of the delivered cost than refining and transporting diesel, and he submitted that the economic evaluations must include the delivered costs of these fuels. The Board notes AEY's submission that using "delivered diesel prices based on Sproule forecast, the LNG option breaks even at an average delivered-LNG-price-to-delivered-price ratio of 75.6 percent over the lifetime of the project."[211]

349. The Board further notes that it was established on the record that the price of energy in natural gas has historically been slightly less than the cost of energy in diesel. The ratio of price of energy in natural gas to the price of energy in diesel prior to 2006 ranged from 70 to 100 percent. In 2006, this ratio dropped to about 60 percent and, more recently, it is at approximately 36.2 percent.[212] The Board agrees with Mr. Maissan that it would take only a small increase in the price ratio to make the LNG option uneconomical. In fact, AEY's data in Table 24, as well as AEY's Reply Argument, show that the project would be viable under some scenarios but not under other scenarios. While the Board understands that slightly positive or positive results are expected under some scenarios, the economic benefits of the Watson Lake project are not sufficiently supported given the outcomes of the various scenarios found in Table 24 and given the corresponding assumptions used by AEY that could impact the financial viability and resulting costs for this project.

350. Further, with respect to the Watson Lake bi-fuel project and the use of diesel units, AEY stated in its business case:

> ATCO Electric Yukon and the Independent Power Producers (IPPs) are pursuing the generation of electricity with renewable resources, however, it is almost certain that a fossil-fueled base load generation source will continue to be required in the short to medium term for reliability of the system. ATCO Electric Yukon believes the switch to a Bi-Fuel Project best accomplishes this base load generation need.[213]

351. Mr. Tenney, in testimony, confirmed that while there is development of future technologies, stand-alone bi-fuel units are not currently available other than for marine applications and that is why conversion units are proposed for this project.[214] Conversion units have not been previously utilized by AEY for utility service to Yukon customers. Conversion of the existing diesel units to bi-fuel is the only option proposed other than use of existing diesel, and in fact, conversion to bi-fuel may be the only other option currently available for the use of LNG at the Watson Lake plant. This raises the issue of whether a bi-fuel conversion should be done at this time given emerging plant technologies related to bi-fuel and LNG instead of relying on the existing diesel units at Watson Lake without bi-fuel conversion. Given the state of emerging technologies and the prospect that such technologies may affect the economic benefits associated with

[211] Exhibit B-5, JM-AEY-24(d).
[212] Exhibit B-5, JM-AEY-24(a).
[213] Exhibit BB-1, Application, Appendix 3, Watson Lake Bi-Fuel Project, Page 7.
[214] Transcript, Volume 3, page 473, lines 13 to 23, Mr. Tenney stated, "So, so far in my discussions and our group's discussions with the suppliers of these equipments, right now the bi-fuel equipment's direct from the factory without a bolt-on kit. So far they're only available in marine applications, and there's not one yet for use at a stationary power plant. So in the near term, I suspect, we're looking at bolting on the bi-fuel kit. But I suspect if it's available in marine applications, as the demand for it grows, they'll likely make it available for stationary power plants."

bi-fuel conversion, the Board finds that the approval of the project as proposed by AEY is not reasonable. Because the impact of the conversion of an individual bi-fuel unit on efficiency, the actual capital costs for conversion as well as the benefits to customers are not sufficiently known and base load generation is currently being supplied to the Watson Lake area by the existing diesel units.

352. The Board is also concerned with AEY's request that the Board approve Phase 1 of the Watson Lake bi-fuel project along with Phase 2 of the project, which will occur entirely in a future test period. Between Phase 1 and Phase 2, the total project costs are $4,695,000 for conversion of diesel units in the power plant that serves Watson Lake and surrounding area, in accordance with AEY's obligation to provide electricity to that area.

353. While the Board acknowledges AEY's position that Phase 2 would be required if Phase 1 is approved and undertaken, the Board does not consider that it is reasonable to approve the need for Phase 2 without the conversion of the unit under Phase 1 given the forecasted costs for the bi-fuel conversion project as proposed.

354. For the above reasons, the Board is not convinced that the benefits and costs are sufficiently supported to approve the project, and therefore denies the Watson Lake bi-fuel conversion project. AEY is directed to remove the bi-fuel conversion costs from its forecast capital additions in the compliance filing to this decision.

9.7.3 Old Crow Unit 3 replacement (Appendix 5)

355. AEY submitted that load growth and load duration of the community of Old Crow have steadily diminished the utilization of the 170-kW Old Crow unit due to its rated capacity. In order to address the load growth issues and ensure that there is sufficient contingency, AEY is proposing to purchase and install a new 600-kW unit to replace the existing undersized 170-kW unit. The new unit will be installed in the new building in Old Crow as it will not be able to fit in the existing building.

356. Based on the 2012 load data provided in AEY's 2013-2015 GRA, AEY submitted that the existing 170-kW unit was approved to be replaced with a 250-kW unit. Notwithstanding the Board's approval, in preparation for tender of the new unit in 2015, AEY submitted that a review of the current loading and consultation with key customers in the community took place. Based on this review and subsequent increases in connected load from 2012, a larger capacity unit (600 kW) was recommended to meet load requirements.

9.7.3.1 Views of interveners

357. Mr. Maissan submitted that the desire to have two independent and completely redundant power plants in the community of Old Crow is well beyond any planning criteria approved by the Board. Mr. Maissan went on to state that the need to have a second building is not in question, but "what is in question is the prudency of the decisions about what size generators to put into this plant which operates as an extension of the existing plant."[215] Mr. Maissan pointed out that a 400-kW generator

[215] JM Final Argument, page 9.

would be running below manufacturers' recommendation "that units are operated in the range of 50-80% of rated capacity."[216] AEY's 50-percent loading target appeared tenuous to Mr. Maissan when he noted that additional solar photovoltaic (PV) capacity is planned for Old Crow. Mr. Maissan submitted that plant efficiency will suffer as the larger generators will be very lightly loaded. In addition, Mr. Maissan submitted that a 400-kW unit could be transported into the community easier than a 600-kW unit. Moreover, considering that more solar PV capacity is planned for Old Crow, Mr. Maissan recommended that the Board reject the plan to install a 600-kW generator in Old Crow and authorize the installation of a 400-kW unit at a cost of $612,000, plus $100,000 to allow for cost increases from the previous 2014-2015 timeframe for this project.[217]

9.7.3.2 Applicant responses to interveners

358. AEY replied that, in his argument, Mr. Maissan failed to take into account the Old Crow peak loading table that clearly demonstrates the need for a 600-kW unit. AEY submitted that it would not be prudent for AEY to invest in assets such as lower-capacity units which do not meet long-term generation needs, based on the assumption that a non-dispatchable renewable resource (i.e. solar PV capacity) may potentially be installed. Furthermore, there is no evidence that the possible installation of a solar generation resource, even with a storage battery, will supply any firm capacity to be relied upon to meet the capacity needs of the community. AEY submitted that this project ensures a continued safe, reliable power source for the community.[218]

9.7.3.3 Views of the Board

359. The Board accepts the proposal as submitted by AEY. The peak loading table included in the Application[219] shows continuous growth since 2012 and the need for a higher-capacity generator. Further, as Old Crow is an isolated community, the Board accepts the submissions[220] of AEY that a full contingency backup for that community is required.

9.7.4 Destruction Bay unit replacement

360. The communities of Destruction Bay and Burwash Landing are serviced by three units located at the Destruction Bay generating plant. The Board approved AEY's request to replace two units in Board Order 2014-06 related to AEY's 2013-2015 GRA.

9.7.4.1 Destruction Bay Unit #2 replacement (Appendix 6) and Destruction Bay Unit #3 replacement (Appendix 11)

361. AEY submitted that the replacement of Destruction Bay Unit #2 was one of the units approved in Board Order 2014-06. The original scope of the project in AEY's 2013-2015 GRA was to replace the unit with a similar sized unit (300 kW). At the time of the unit tender and selection, capacity requirements were reviewed, and as a result, AEY submitted that it will tender and procure a 400-kW unit. The total cost of this project

[216] Exhibit B-5, JM-AEY-27 (b).
[217] JM Final Argument, pages 9 and 10.
[218] AEY Reply Argument, paragraphs 107 to 109.
[219] Exhibit BB-1, Application, Appendix 5, pages 1 and 2.
[220] Transcript Volume 3, starting at page 483, line12 and ending page 485, line 23.

is forecasted to be $758,000, compared to the $600,000 capital expenditure previously approved by the Board. AEY indicated that receipt of the unit and installation is scheduled to be completed in 2016.

362. AEY submitted that the replacement of Destruction Bay Unit #3 was one of the units approved in Board Order 2014-06. AEY clarified that the existing 220-kW unit was to be replaced with a larger unit (250 kW) in order to ensure that the unit would continue to operate for a reasonable amount of hours to meet load requirements.

363. AEY stated that the purchase of a new 250-kW unit was put out to tender in 2013; however, none of the bidders in the RFP process submitted bids for a 250-kW unit. Of the bids received, and after a further analysis of best fit for the power plant and community load profile, AEY selected a 312-kW unit. Receipt of the unit and installation was scheduled to be completed in 2014.The total cost of this project was $634,000, compared to the approved cost of $450,000.[221]

364. AEY explained that the actual costs "were higher mainly due to foundation issues discovered, subsequent to the initial forecast, as well as additional control work required due to the delay of the Destruction Bay PLC upgrade."[222] AEY confirmed that receipt of the unit and installation was "completed, prior to the recent installation of the increased amount of solar PV generation."[223]

9.7.4.2 Views of interveners

365. With respect to AEY's proposal to replace the two smaller units in the Destruction Bay diesel plant with larger units, Mr. Maissan pointed out that a fair bit of solar capacity has been added in Destruction Bay in recent years and significant efforts are underway to establish a wind project of 300 kW in the area. Mr. Maissan expressed concerns that AEY is opting for larger diesel generators than necessary for reasons other than efficient plant performance, and the reasons for his position include that AEY is:

> …providing themselves with a stronger negotiating position with respect to a PPA with the Kluane wind project — which AEY has been aware of for many years. The choices seems designed to frustrate or obstruct to the extent possible the installation of renewable energy in this diesel served community. The choice of 400 kW and 312 kW generators to replace generators of 300 kW and 220 kW will reduce opportunity for, and add costs to, renewable energy projects in Destruction Bay – Burwash Landing…[224]

366. Mr. Maissan recommended that the Board direct AEY to replace one of the existing smaller units with the installation of one 400-kW unit. Mr. Maissan also recommended that the Board direct the replacement of Destruction Bay Unit #3 (CUL 230 220 kW unit) with a unit no larger than 250 kW. AEY should be directed to provide the 2015 load duration curves for Destruction Bay plant in its compliance filing. Mr. Maissan recommended:

[221] Exhibit BB-1, Application, Appendix 11, page 1.
[222] Exhibit BB-1, Application, Appendix 11, page 1.
[223] Exhibit B-5, JM-AEY-27 (a).
[224] JM Final Argument, page 15.

> … that the Board order AEY, in negotiations for an IPP with the proponents of the Kluane wind project [sic] to allow diesel displacement down to a load level to the lowest normal 2015 dispatch level without penalty or cost to the proponent.[225]

9.7.4.3 Applicant response to interveners

367. AEY pointed out that the two Destruction Bay unit replacement projects were scheduled — and in the case of Unit #3 replacement, completed — prior to the recent installation of solar PV generation in the Destruction Bay and Burwash communities. AEY acknowledged that the Burwash Landing wind project may eventually be a source of renewable energy on the Destruction Bay/Burwash micro-grid. However, AEY submitted that:

> … it is not prudent or common practice for a utility to reduce the installed capacity of its generation facilities as a result of the possible installation of a non-dispatchable renewable resource, regardless of whether it is owned and operated by a third party or the utility itself.[226]

368. With respect to determining the size of Destruction Bay Unit #2, AEY considered the capacity as well as operational efficiency requirements. AEY submitted that replacement of Unit #2 with a new unit of the same size (300 kW) would not have allowed AEY to meet operational efficiency requirements, as units would have been under or overloaded during automated dispatch. AEY added:

> … at the current dispatch level there are times in which Unit 2 is operated at an overload condition in respect to its prime rating. The only solutions to this overload issue are to de-rate the unit or replace it with a larger unit. If the de-rate option was selected, it would negatively impact the operation of Unit 1, forcing it to run in a low loading mode. Selecting a larger unit allows Unit 2 and Unit 1 to be dispatched in a more efficient manner.[227]

369. AEY submitted that contrary to Mr. Maissan's assertions, the sizing considerations were done to meet firm capacity requirements and to allow for an efficient dispatch of the units, all of which are in line with AEY's obligation to serve customers with safe and reliable electricity.

9.7.4.4 Views of the Board

370. Destruction Bay Unit #3 was approved in AEY's 2013-2015 GRA. The unit was substantially completed and operational in 2014, with final acceptance in 2015. Further, the Board notes that Unit #3 replacement was completed prior to the recent installation of solar PV generation in Destruction Bay and Burwash Landing.

371. AEY determined through the tender process that the best fit for the power plant and community load profile was a 312-kW unit rather than the originally forecast capacity of 250 kW. The final cost of the project was $184,000 over the GRA-approved forecast. AEY indicated that the variance between the actual and forecast costs was

[225] JM Final Argument, page 15.
[226] AEY Reply Argument, paragraph 112.
[227] AEY Reply Argument, paragraph 117.

due to foundation issues discovered subsequent to the initial forecast and additional control work. AEY added that movement to the larger generator capacity would increase operational hours of the unit and concomitantly increase the units' efficiency.[228]

372. The Board finds the reasons provided by AEY — operational efficiency, community and load profile[229] — support the need for the larger capacity unit. In addition, the cost for the larger unit and the need to mitigate the foundation issues identified are acceptable reasons for the cost variance. The Board approves the costs as filed. Although wind capacity may eventually be a source of renewable energy on the Destruction Bay/Burwash micro-grid, the Board accepts AEY's submission that wind generation will not contribute to firm capacity requirements within the test period.

373. With respect to Unit #2, the Board notes AEY's submission that replacement of this unit with a similar-sized unit would not have allowed AEY to meet the Operational Efficiency Requirements, as units in the generation plant would have been under or overloaded during automated dispatch. Therefore, the Board approves the additional costs associated with the larger 400-kW unit.

374. Considering the above, the Board approves AEY's replacement of Destruction Bay Units #2 and #3, as filed.

9.7.5 McIntyre subdivision rebuild (Appendix 8)

375. The McIntyre subdivision rebuild is a multi-phase project to replace the existing end-of-life underground electrical infrastructure serving the McIntyre subdivision in the City of Whitehorse. The original forecast for Stage 1 was approved as part of AEY's 2013-2015 GRA in Board Order 2014-06.

376. AEY referred to this project as being a complex "brownfield" infrastructure replacement. The original underground electrical system serving the subdivision is operating at 35 kV and was installed circa 1977. The proposed project will convert the subdivision's operating voltage to the standard 25-kV system. AEY indicated that 25-kV equipment is standard in Whitehorse's distribution system and provides improved electrical performance for residential customers.

377. The original scope of the project was to install a new 25-kV underground electrical system in close proximity to the existing 35-kV system. As Stage 1 was underway, AEY discovered that the location of the existing underground system would be in constant conflict with the installation of the new system. This made the field construction more time-consuming. Time constraints imposed on construction permits from the Kwanlin Dun First Nation (KDFN) made it necessary that a new project scope be developed. AEY explained the change in project scope due to installation issues:

> The new project scope involved the installation of a temporary overhead shadow electrical system which would allow construction crews to install the new underground system with the old underground system safely deenergized. This would allow the construction crews to work at a similar pace to a

[228] Exhibit BB-1, Application, Appendix 11, page 2.
[229] Exhibit BB-1, Application, Attachment 11.4, page 1.

> Greenfield project. The work would also include the installation of low voltage pedestals to connect to the overhead system and a new main underground feed to the subdivision.[230]

378. The following table shows approved costs, AEY's actual costs, and its forecast costs for the McIntyre subdivision replacement project:

Table 25. **McIntyre subdivision rebuild — 2013 to 2020 — actual (A) and forecast (F) costs ($000s)**

Year	Actual/Forecast	Streetlights	Total	Scope
2013 (A)	656	-	656	Temporary overhead
2014 (A)	418	-	418	Low voltage pedestals, connected to feeds
2015 (A)	379	-	379	Main underground feed to the subdivision
2016 (F)	565	175	740	Hanna and McCandless
2017 (F)	930	256	1,186	Murphy (partial), O'Brien, and McCrimmon
2018 (F)	500	100	600	McClimon
2019 (F)	600	150	750	Complete Murphy, McIntyre up to McCauly
2020 (F)	300	100	400	McCauly to Hamilton to McIntyre
Total	**4,348**	**781**	**5,129**	

Source: Exhibit BB-1, Application, Appendix 8, Table 1, Page 3.

379. In a letter[231] dated October 24, 2016, AEY submitted that it is seeking Board direction as to the appropriate treatment of the potential cost savings, should the KDFN accept one of the alternatives such as "Alternative 2" in the business case provided in Appendix 8 of the Application. The business case included the following:

> Alternative 2: Explore the benefits of utilizing some of the overhead system in coordination with some of the new underground electrical infrastructure. This would result in a hybrid system as it would be a combination of overhead and underground. This alternative would require the approval of the KDFN.[232]

380. AEY submitted that it is anticipated that "Alternative 2" would alter the work required and result in a potential cost savings in 2018-2020, which is outside of the test years. AEY clarified that it is requesting the Board to provide direction as to whether or not the expected costs savings could be applied as an offset to the contribution required by the KDFN in the future.

9.7.5.1 Views of the Board

381. The Board notes that interveners did not comment on AEY's request.

382. During the hearing, the Board notes AEY's submission that it had extensive meetings with KDFN. AEY submitted, "It's very clear that they want to have an underground power system when we're done in there… that's what they would like to have when we leave that subdivision at the end of the project."[233] Moreover, the Board

[230] Exhibit BB-1, Application, Attachment 11.4, page 1.
[231] Exhibit B-13, YECL letter to YUB re corrections, updates and clarifications, October 24, 2016.
[232] Exhibit BB-1, Application, Appendix 8, McIntyre Subdivision Rebuild, page 3.
[233] Transcript, Volume 1, page 151, lines 1 to 5.

notes AEY submission that "… there was an original customer contribution when the original system went in back in the '70s, so we wouldn't be asking the customer to recontribute."[234]

383. The Board notes that the ultimate scope of the project has not been determined by AEY at this time. AEY submitted two project alternatives: (1) an underground system, or (2) a hybrid system (combination of overhead and underground).

384. The Board accepts AEY's test-period forecast costs because this is an ongoing replacement project. However, because the scope of the project has not been finalized, AEY is directed to provide an updated business case in its next GRA.

385. If AEY's proposal for "Alternative 2" (a hybrid system) is explored and is to be implemented, the Board directs AEY to include in its updated business case any revised forecast costs and cost savings.

386. The Board will provide further direction in the next GRA regarding AEY's request as to whether or not the expected cost savings could be applied as an offset to the contribution required by the KDFN.

9.7.6 Significant capital projects

387. In Board Order 2009-2, the Board directed "YECL to provide business cases for all major capital expenditures at the time YECL files its rate applications to give the Board and Intervenors better opportunity to examine the business cases and time to allow for written information requests."[235] In Attachments 9.1 and 9.2 of the Application, AEY provided a listing of capital expenditures for 2016-2017, which included project descriptions for projects greater than $100,000. AEY also provided business cases for all major capital projects ($500,000 or greater) in Appendix 1 to Appendix 11 of the Application.[236]

388. UCG noted the Board's consideration in its January 2007 Report to the Commissioner in Executive Council re YEC's 20-year resource plan[237] that given the smaller rate base in the Yukon and the small number of ratepayers in the Yukon, a $1-million threshold would be appropriate for capital expenditures to be reviewed by the Board pursuant to Part 3 of the *Public Utilities Act.*

389. Considering the above, UCG recommended that the following projects should be reviewed pursuant to Part 3 of the *Public Utilities Act:*

(a) McIntyre subdivision rebuild;[238]

(b) Watson Lake bi-fuel projects;[239]

(c) Watson Lake Unit #2 replacement;[240]

[234] Transcript, Volume 1, page 152, lines 5 to 8.
[235] Board Order 2009-2, Appendix A: Reasons for Decision, page 37.
[236] Exhibit BB-1, Application, page 9-5.
[237] Yukon Utilities Board Recommendations YEC 20-Year Resource Plan: 2006-2025, Page 28, issued January 15, 2007.
[238] UCG Final Argument, paragraph 187.
[239] UCG Final Argument, paragraph 192.
[240] UCG Final Argument, paragraph 197.

(d) Downtown Whitehorse capacity improvement project;[241]

(e) Old Crow Unit #3 replacement;[242]

(f) Whistle Bend Subdivision Stage 3-C project;[243]and

(g) Fish Lake Ditch #3 diversion replacement project.[244]

9.7.6.1 Views of the Board

390. With respect to UCG's submission that the above-mentioned projects be reviewed pursuant to Part 3 of the *Public Utilities Act,* the Board considers that this request is premature because neither application has been made to the minister under section 39 of the *Public Utilities Act*, nor has the minister designated any of the projects as a regulated project under section 37 of the *Public Utilities Act*. Moreover, the Board does not determine that projects are Part 3 projects under the *Public Utilities Act*, but makes recommendations on energy projects only when the minister refers them to the Board. Accordingly, the Board finds that UCG's recommendations on Part 3 projects and associated capital expenditures do not apply.

10 Income tax

391. In its Application, AEY continued to use the flow-through method for calculating income tax expense. This method was approved by the Board in Board Order 2014-06. AEY argued that since the use of the flow-through method was not raised as an issue by any party during the testing of its Application, the Board should continue to approve the use of this method.

10.1 Views of the Board

392. The Board agrees with AEY that there is no reason to change the currently approved flow-through income tax method used by AEY in its Application. AEY's method of determining income tax expense to be recovered through rates is approved as filed.

11 Previous Board directions

393. AEY provided the following responses to prior Board directions from Appendix A: Reasons for Decision from Board Order 2014-06:

Board Direction	AEY Response	Board Comment
Direction 8, Page 51. The Board agrees with the submissions of UCG that no assessment has been provided	*Application, page 11-1,* ATCO Electric Yukon has engaged Concentric Energy Advisors Ltd. to undertake an	Upon review of the Application and AEY's explanation, the Board finds that AEY has complied with the direction. No

[241] UCG Final Argument, paragraph 202.
[242] UCG Final Argument, paragraph 207.
[243] UCG Final Argument, paragraph 212.
[244] UCG Final Argument, paragraph 217.

within this proceeding regarding the comparability of YECL to the BCUC benchmark utility Fortis Energy. The previous risk premium was based on FortisBC, which is an electrical distribution company. BCUC Order G-75-13 — the Stage 1 GCOC proceeding decision dated May 10, 2013 — identifies Fortis Energy as a gas distribution utility. Other than it being a distribution and regulated utility, no other comparisons to YECL can be gleaned from the benchmark decision. As a result, the determination of whether a risk premium should be applied is not clear. The Board finds that YECL has not established a prima facie case to quantify a risk premium over the BCUC benchmark utility. Therefore, the Board directs YECL, in its compliance filing to use an ROE of 8.75 percent, an ROE equal to that for the BCUC GCOC benchmark utility. YECL is also directed to provide justification for a risk premium relative to the BCUC GCOC standard in its next GRA.	analysis as to whether a risk premium over the BCUC GCOC benchmark utility is appropriate and if so, the quantum of such premium. Their analysis is contained in Attachment 8.1 included in section 8 of this Application.	further response is required.
Direction 12, page 62. The Board understands that YECL needs to explore alternatives respecting the use of wind to generate power in the area of Burwash and Destruction Bay, which interveners have been promoting. Accordingly, the Board finds the study costs warranted and reasonable. In addition, the Board directs YECL in its next GRA to provide results of the feasibility study.	*Application, page11-2.* ATCO Electric Yukon contributed funds ($20,000) towards this initiative in 2013 and received a report titled “Burwash Landing and Destruction Bay Wind-Diesel Prefeasibility Update.” ATCO Electric Yukon filed this report in response to Undertaking 17 during the 2013-2015 GRA hearing. Since that time ATCO Electric Yukon has received one further update in early 2014 but ATCO Electric Yukon is no longer engaged in this project and no further contributions have been made to this project, as such, ATCO Electric Yukon is not expecting to receive any further reports arising from this initiative.	Upon review of the Application and AEY’s explanation, the Board finds that AEY has complied with the direction. No further response is required.

Direction 13, page 64. YECL needs to provide information in relation to project costs overruns in its Application. Therefore, the Board directs YECL in future applications to explain more fully the reasons for project overruns. For clarity, for project costs overruns that are (collectively) 100-percent over and $100,000 greater than the original estimate, YECL is to provide business case type descriptions in the Application, to alert interveners and the Board to the cost overruns, thereby allowing for a more efficient process to examine the cost overruns. Furthermore, YECL, in their explanations, are to explain why the nine expenditures were not foreseen and actions it takes to ensure that such overruns will not occur in future. Moreover, for projects similar in nature to the Oracle HRxcellence HR management project with expenditures greater than $100,000, which may arise between GRAs, YECL, in future applications, is directed to furnish business cases for such projects and the reasons why YECL deemed it necessary and reasonable to proceed with the project.	*Application, page 11-3 to 11-4.* ATCO Electric Yukon has included project completion summaries for all projects listed below that were forecast in the 2013-2015 GRA where actual costs were 100 percent and $100,000 greater than the original forecast. In addition, ATCO Electric Yukon has included a project completion summary for the Fish Lake Dyke Upgrade to explain the variance in actual costs to forecast for that project. Business cases have also been provided for completed projects where the actual costs were in excess of $100,000 and for which no business case was provided in the 2013-2015 GRA. ATCO Electric Yukon has included business cases for the completed projects listed below in Attachments 11.7 through Attachment 11.13.	Upon review of the Application and AEY's explanation, the Board finds that AEY has complied with the direction. No further response is required.
Direction 14, page 70. The Board rejects UCG's recommendation because it is the actual amounts spent on projects that are added to rate base. The Board therefore approves other small project costs. That being said, the Board notes YECL's submission that expenditures "forecast as Other Projects are subsequently able to be broken down into greater detail when actual amounts are reported. Looking only at the variance for Other Projects does not provide an accurate picture of variance in the actual amounts spent for capital additions as compared to the forecast." Bearing this in mind, in	*Application, page 11-5.* In section 9, Schedule 9.2 of this Application, ATCO Electric Yukon has provided a detailed listing of all projects completed and actual amounts spent by project from 2013 through 2015. ATCO Electric Yukon has continued to group various projects in the "Other projects less than $20,000" category in Schedule 9.2, and submits this approach is appropriate considering the aggregate totals in this category are under the threshold of $100,000 highlighted in Direction 13.	Upon review of the Application and AEY's explanation, the Board finds that AEY has complied with the direction. No further response is required.

order to help the Board and interveners examine more efficiently and process an application, the Board directs YECL, in future GRAs, to indicate in their applications how the approved forecast Other Projects amounts are subsequently spent.		
Direction 15, page 71. The Board accepts, based on the evidence, that the expenditures were reasonable and prudent in the circumstances. The Board rejects UCG's recommendations because the business case was not required for each related component and seeing the Board's finding of prudency. However, in future GRAs, the Board directs YECL to provide business cases for completed related projects which may span multiple years and total more than $500,000.	*Application, page 11-6.* On Schedule 9.2 of the Application, ATCO Electric Yukon has included the reference to where the business cases can be found in either the 2013-2015 GRA or in Appendix 1-11 of this Application. Business cases have been provided for all projects that span multiple years where costs were expected to be greater than $500,000.	Upon review of the Application and AEY's explanation, the Board finds that AEY has complied with the direction. No further response is required.
Direction 20, page 101. As argued by CW and UCG, the Board recognizes that the forecast risks with respect to the DSM program are one-sided. If participation rates are lower than expected, the utilities benefit, but if participation rates are higher than expected, the utilities have the ability to enforce the budget. Therefore, in the Board's view, a deferral account would not only protect ratepayers but it would also normalize the incentive for the utilities to maximize participation in the DSM program. Accordingly, the Board orders YECL to track all DSM programming costs occurring in 2014 and 2015 in a deferral account and to apply for recovery of those costs in its next GRA. Further, the Board affirms it does not approve the program for the five-year term requested and that the utilities are to make a formal application to the Board before expanding the DSM program elements beyond that approved above or beyond 2015. The Board directs YECL, within its compliance	*Application, page 11-7.* The DSM programming costs approved in Board Order 2014-06 for the 2014 and 2015 test period have been tracked as directed in deferred charges. ATCO Electric Yukon was unable to complete the program as originally designed and spend all of the approved DSM program costs in 2014 and 2015 period; therefore the remaining approved amount will be spent in 2016. ATCO Electric confirms that it has not changed the scope of the approved DSM program. In this Application, ATCO Electric Yukon is applying for recovery of these previously approved costs (incurred from 2014 through 2016) over the next five years in a manner consistent with the previously approved DSM costs.	Upon review of the Application and AEY's explanation, the Board finds that AEY has complied with the direction. No further response required.

filing, to quantitatively provide the load reduction in GW.h related to DSM for each of the years 2014 and 2015, by rate class that has been incorporated in YECL's load forecast and to explain and quantify the changes to the load forecast based on the determinations of the Board regarding DSM.		

12 Deferral accounts

394. In its Application, AEY proposed deferral-account treatment for three new cost categories, while maintaining deferral treatment for those categories previously approved by the Board. AEY's summary of existing and proposed deferral accounts is shown in the following table:

Table 26. **Summary of existing and proposed deferral accounts**

Name of existing or proposed deferral account	Existing	Proposed
Rate case costs	X	
Defined benefit pension plan	X	
Feasibility study or program: DSM program (approved program) Watson Lake LNG — phase I (approved study) Renewables study (proposed study) Joint grid study (proposed study)	X	
Purchase power flow-through	X	
Diesel fuel	X	
LNG fuel		X
Board order or changes in legislative provisions		X
Statutory Federal and Territorial income tax rates		X

Source: Summarized from Application

395. The Board has considered the five existing deferral accounts and finds that their respective intent and scope have not changed. AEY's existing deferral accounts continue to be approved.

396. In the following sections, the Board will discuss the three new deferral account categories proposed in AEY's Application and whether they should receive deferral-account treatment.

12.1 LNG Fuel Deferral

397. Please refer to the section 4.5 of this decision.

12.2 Board Orders or Changes in Legislative Provisions Deferral

398. In its Application, AEY sought the ability to flow through, dollar for dollar, costs related to Board Orders or legislative provisions resulting in changes to the rules or parameters that AEY operates under for the 2016-2017 test period.

399. The IPP Policy for Standard Offer Prices was cited as one example in support for this deferral account.

400. In argument, AEY claimed that in future, there is no guarantee of stakeholder input or significant lead time. AEY added that it has no control over these policies or programs and has no way to forecast with certainty the impact related to these types of programs, and therefore seeks deferral account treatment.[245]In reply, AEY challenged the assertions of Mr. Maissan about the micro-generation program, stating that the response to JM-AEY-5(c-d)[246] did not include the full costs incurred by AEY (such as administrative costs), adding that there is no certainty of that program continuing to operate in its current manner.[247]

401. AEY did agree with Mr. Maissan in that it is a stakeholder in relation to the development of the IPP program. However, AEY countered that it does not control the actual implementation of the program and that it would be at risk for any changes until its next GRA.[248]

12.2.1 Views of interveners

402. John Maissan did not support the AEY request for a Board Orders or Changes in Legislative Provisions Deferral Account. Mr. Maissan noted that the micro-generation program provided net benefits to AEY. In regard to the IPP program, AEY has been an active participant along with the Yukon government, Yukon Development Corporation (YDC) and YEC .

403. The effects of the commercial energy incentive program run by the Yukon government were another reason cited by AEY for this deferral account. Mr. Maissan argued that the effects of this program are captured within AEY's load-forecasting process, and thus had minimal impact.[249]

404. UCG stated that a deferral account to track costs related to Board Orders or legislative provisions does not provide AEY with the ability to flow costs through, dollar for dollar, to ratepayers. A deferral account simply tracks costs for review and possible recovery at a later time.[250]

12.2.2 Views of the Board

405. In AEY's 2013-2015 GRA, AEY requested a deferral account to flow through, dollar for dollar, to the tariff any costs related to Board Orders or legislative provisions

[245] AEY Final Argument, paragraphs 11-12.
[246] Exhibit B-5 — YECL Responses to Maissan Requests
[247] AEY Reply Argument, paragraph 13.
[248] AEY Reply Argument, paragraph 14.
[249] JM Final Argument, page 1.
[250] UCG Reply Argument, paragraph 13.

resulting in changes to the rules or parameters that AEY operates under or that bear on the nature and extent of AEY's obligations as a regulated utility and which impact its 2013 to 2015 revenues or revenue requirement.[251]

406. In Board Order 2014-06, the Board ruled that:

> … on most occasions that the Board has witnessed, legislative change involves extensive stakeholder input and significant lead time before the change is implemented… The Board finds that YECL would have sufficient time to incorporate any such changes at the time of any GRA filing. Therefore the Board rejects YECL's request for this deferral account.[252]

407. The Board's views have not changed. The evidence in this proceeding is that AEY has been able to actively participate in potential legislative changes respecting the implementation of new programs, so AEY has not shown the need for such a deferral account. The Board notes Mr. Maissan's comments about little or no impacts of the programs referred to by AEY. The Board denies AEY's request for a Board Orders or Legislative Provisions Deferral Account.

12.3 Statutory Federal and Territorial Income Tax Rates Deferral

408. In its Application, AEY requested deferral-account treatment for income tax beginning in the year 2016. The deferral amounts would be based on any deviance from enacted federal and territorial statutory rates, which were each currently set at 15 percent. AEY submitted that any changes from these rates would be used to determine an updated revenue requirement that, when compared to final approved revenue requirement, would initiate either a refund to or collection from customers for the difference.

409. AEY cited uncertainty with respect to global economics and recent federal government changes as increasing the possibility of significant tax changes between GRAs. During the hearing, AEY witness James Grattan indicated a further potential for changes to the territorial statutory rate depending on the outcome of the territorial election.

410. In argument, AEY summarized:

(a) Changes in statutory tax rates can be material;

(b) Given that the statutory rates are set by the Territorial and Federal Governments and these rates are not published in advance of annual budgets, there is uncertainty regarding forecast accuracy;

(c) The statutory rates are determined by the Territorial and Federal Governments, and tare [sic] therefore beyond AEY's control; and

[251] Board Order 2014-06 – Appendix A: Reasons for Decision, page 1.
[252] Board Order 2014-06 – Appendix A: Reasons for Decision, page 103.

(d) AEY is not typically at risk with respect to items that are beyond its control and that are material.[253]

12.3.1 Views of the Board

411. The Board considers that the need for a deferral account has not been shown given the two-year test period. Further, the criterion for a deferral account is that AEY is typically at risk with respect to items that are beyond its control and that are material. In the Board's view, AEY has not shown that it is at risk or that any risks are material from changes in federal or territorial income tax rates. For these reasons, the Board denies AEY's request for a deferral account for statutory federal and territorial income tax rates.

12.4 Deferred Charges and Credits

412. For those account categories currently approved for deferral-account treatment, AEY monitors charge and credit transactions.[254] Generally, AEY will incur the deferral-account related expenditures over time and will subsequently recover the approved costs through deferral account revenue requirement. This is currently the treatment ascribed to hearing costs and deferred pension costs, each of which were forecasted to be recovered in revenue requirement evenly over the years 2016 and 2017.

413. In its Application, AEY proposed similar treatment for the tracking and recovery of costs related to feasibility or other studies, such as those pertaining to Watson Lake, Renewables and Alternative Energy, and a Joint Smart Grid. In some cases, after the study was completed, AEY proposed to recover the study costs within its deferral accounts over a period of two years. In the alternative, and as is the case with the deferred DSM program costs, AEY proposed to capitalize the costs into rate base and amortize them over a specified period of time.

414. UCG provided a general comment that, "All deferred study costs should be removed from rate base and either amortized (if prudent) outside of rate base or rolled into a related capital asset."[255]

415. UCG submitted that study costs do not meet the "used or required to be used" test for consideration as a utility asset providing utility service to customers, despite that the costs may have been incurred prudently.[256]

416. Interveners raised other concerns with respect to AEY's proposed recovery of these study-related costs, each of which are discussed in the four sections that follow.

12.4.1 Demand Side Management (DSM) Program Study Deferral Account

417. AEY proposed[257] to move costs related to the approved DSM program study out of the deferral account and into rate base. Notwithstanding an issue related to the use of the mid-year convention for depreciation purposes addressed elsewhere in this

[253] AEY Final Argument, paragraph 164.
[254] Exhibit BB-1A AEY GRA Schedules, schedule S8.8.
[255] UCG Final Argument, paragraph 30.
[256] UCG Final Argument, paragraphs 166-174.
[257] AEY Final Argument, paragraphs 115-118.

decision, AEY stated that the use of a five-year amortization period (2014-2018) for cost recovery was consistent with the Board's direction in section 12.1 of Board Order 2014-06.

418. AEY stated that evidence of prudent expenditures related to the DSM program was provided in interim evaluation reports and these reports concluded that the DSM programs were well-received by Yukoners, were cost-effective, and that participation met or exceeded most KPIs.

419. In response to UCG's recommendation that deferred study costs should be removed from rate base, and either amortized outside of rate base or rolled into a related capital asset, AEY stated that the DSM program study costs in this case were for programs previously approved by the Board.

12.4.1.1 Views of interveners

420. UCG[258] questioned why the deferred DSM program costs would subsequently be treated as a capital item and attract carrying costs like other assets placed into rate base. UCG submitted that AEY was entitled only to the return of, and not a return on, prudently incurred DSM costs.

421. YEC[259] disagreed with UCG's suggestion that the DSM study costs should not be treated as capital assets earning a return on the same basis as other rate base elements. YEC submitted that UCG's recommendation should be disregarded by the Board.

12.4.1.2 Views of the Board

422. The Board can find no basis to consider UCG's recommendation that AEY was entitled only to the return of, and not return on, the DSM program study costs. AEY's treatment of these costs — by way of capitalization into rate base, and the attendant calculations of depreciation and return — is consistent with the Board's direction in section 12.1 of Board Order 2014-06. For this reason, the Board does not accept the recommendation made by UCG. The Board approves the transfer of the DSM program study costs out of the deferral account and into rate base to be amortized over a period of five years, as proposed by AEY.

12.4.2 Watson Lake LNG Study Deferral Account

423. In its Application, AEY requested approval for $494,000 in study and development costs related to the Watson Lake bi-fuel project. AEY proposed to recover these forecast costs evenly over the 2016-2017 test period through the study's associated deferral account. AEY submitted that the study costs were incurred prudently and should be recovered from customers whether or not any of the Watson Lake bi-fuel project capital costs are approved.[260]

[258] UCG Final Argument, paragraph 228,.
[259] Yukon Energy Reply Argument, pages 9-10.
[260] AEY Final Argument, paragraphs 105-108.

424. As an alternative, AEY stated that it was not opposed to capitalization of the study costs, should the Watson Lake project be approved, with subsequent cost recovery over the lifetime of the related assets.[261]

12.4.2.1 Views of interveners

425. UCG argued that in Board Order 2013-01, the Board determined that feasibility expenditures associated with projects deemed to be feasible should remain in "Work in Progress" until such time that the project is set aside or the utility comes before the Board for a prudence review. In Board Order 2014-06, the Board determined that Watson Lake bi-fuel project study costs would be held in "Work in Progress" until such time as the project may be completed.

426. UCG submitted that if the Board accepts the proposed Watson Lake bi-fuel project proposed by AEY, then $494,000 in Watson Lake Study costs should be rolled into the capital costs of that project and recovered over the life of the Watson Lake bi-fuel project.

427. Consistent with his views that the Watson Lake bi-fuel project itself be denied by the Board, Mr. Maissan recommended that all actual study costs expended to date should be amortized over a five-year period.[262]

12.4.2.2 Views of the Board

428. The Board does not consider that adding complexity with respect to the recovery of the Watson Lake LNG study costs is necessary. To recover the study costs over the life of the Watson Lake bi-fuel project, as was recommended by UCG, would require an allocation of the study costs to several individual account numbers, each with a unique service life. The Board has determined doing so would not result in an efficient or straightforward process of cost recovery and would be unduly onerous. Further, since in section 9.7.2 of this Order the Board has rejected the Watson Lake bi-fuel project, this issue of rolling the study costs into the capital costs is moot. For these reasons, UCG's recommendation is denied.

429. The Board accepts Mr. Maissan's recommendation that recovery of the Watson Lake study costs and development costs forecast in the amount of $494,000 should be on the basis of an amortization period of five years. This period of time is consistent with that used for the recovery of the DSM program study costs. The Board finds this to be a reasonable approach for the recovery of the Watson Lake bi-fuel study costs.

12.4.3 Renewable and Alternative Energy Feasibility Study Deferral Account

430. AEY proposes to include $300,000 in 2016 and $200,000 in 2017 as charges related to work it has planned regarding the Renewable and Alternative Energy Feasibility study.[263] The $500,000 in costs for the study would be recovered through AEY's deferral account in the amount of $150,000 in 2016 and $350,000 in 2017.

[261] AEY Final Argument, paragraph 108..
[262] JM Final Argument, page 15.
[263] Also referred to in AEY's application as the "Renewables Feasibility Study"; Exhibit BB-1, page 8-8 and Schedule 8.8.

431. AEY proposed to assess individual communities and retain third party expertise to carry out the studies through a combination of competitive processes and "sole-sourcing."[264] The studies are intended to identify the optimal size and configuration of company-built, -owned and -operated renewable and alternative energy generation in each of the five isolated communities served by AEY which currently rely on diesel power generation. The studies will also assess energy storage systems and potential improvement for energy efficiency through waste-heat recovery opportunities in each of the communities.

432. Once the studies are complete, AEY proposed that any technically and economically feasible projects identified therein would be brought forward as business cases in stand-alone proceedings for approval by the Board. This would ensure customers receive more immediate benefit of the studies and resulting projects, without the need to wait for a subsequent GRA.

433. Further, AEY indicated its commitment that, subject to any confidential or proprietary information contained in the renewable energy studies, they would be prepared to share the study publicly in connection with any resulting application or earlier in an appropriate forum, such as the utility's website.

434. During the oral hearing, AEY witnesses confirmed that preparation of the renewables study was behind schedule and that no work had been completed at that time.[265]

435. In response to UCG's recommendation that deferred study costs should be removed from rate base and either amortized outside of rate base or rolled into a related capital asset, AEY stated with respect to feasibility studies, such as the one proposed for renewables, deferral treatment for approved expenditures is appropriate given that such studies may not result in the construction of a project, or a near-term project.[266]

12.4.3.1 Views of interveners

436. Given that AEY had not commenced development of its proposed renewables study, Mr. Maissan argued it was unreasonable to expect that AEY could incur the entirety of its proposed expenditures in a prudent manner subsequent to a Board Order.

437. Mr. Maissan also took issue with AEY development of company-owned renewable and alternative energy sources, stating that such projects would be in direct competition with IPP proponents. Mr. Maissan viewed it to be inappropriate for ratepayers to fund AEY to, in essence, compete with the private sector, which is funded privately.

438. As an alternative to the Board approving a $500,000 renewables study, Mr. Maissan recommended that the Board should approve (1) study costs of up to $150,000 "to prepare for the significant displacement of diesel generation in Destruction

[264] AEY Final Argument, paragraph 110..
[265] Transcript, Volume 2, page 292.
[266] AEY Reply Argument, paragraphs 88-90..

Bay – Burwash Landing, Old Crow, and Watson Lake using renewable energy sources, including wind and solar PV", and (2) study costs of $50,000 "for a study on how to improve the fuel efficiency of AEY's diesel plants, including the utilization of residual heat, that applies to all of AEY's diesel plants."[267]

439. With respect to each of his proposed studies, Mr. Maissan made further recommendation that the Board order AEY to submit detailed terms of reference, submit study reports upon their completion, and also seek Board approval before the implementation of any action arising out of the study findings.

440. YCS expressed similar views to that of Mr. Maissan in that the concept of the renewables study as pursuing a replacement for diesel fuel was flawed and should be denied by the Board. YCS stated that if ratepayers were being asked to pay for the study, then it must be shared as soon as completed and not withheld from viewing until the next GRA.[268]

441. YEC[269] discounted Mr. Maissan's argument that AEY developing renewable and alternative energy sources would be in competition with IPP proponents. YEC stated there was no basis for Board to restrict prudently incurred expenditures related to studies assessing renewable generation options.

442. YEC also addressed comments from Mr. Maissan and YCS requesting the sharing of any renewable study results prior to AEY's next GRA, stating that there is no mandate for the Board to address such proposals. YEC expressed similar views with respect to AEY's proposal to bring forward any business cases stemming from the renewables study in a stand-alone proceeding before the Board without waiting for a subsequent GRA.

12.4.3.2 Views of the Board

443. In this test period, AEY has requested various studies for Board approval to include amounts for studies in rates. The Board considers that such studies are best conducted by industry or funded by government initiatives.

444. In addition, the Board understands that it may be difficult for the utility look to government grants or other sources of funding through customer rates without a fully formulated proposal for a renewable or alternate energy project. This was explained by Mr. Tenney in his testimony:

> Q. Are you aware, gentlemen, at this time of any further funding opportunities for projects stemming from the renewable study from either the Federal or Territorial Governments that may be known to you or have been — become public since you filed your application and your IRs?
>
> A. MR. TENNEY: Again, in one of the information responses, we did talk about the last — the 2016 federal budget that they earmarked, I believe it was $10.6

[267] JM Final Argument, page 12.
[268] YCS Final Argument, page 9.
[269] YEC Reply Argument, pages 7-9.

> million for renewable energy programs. We have been working with the Federal Government to see if we can access that.
>
> To date, the message — and I think we — in one of that - October 24th, I believe it was, update that we did, we had originally said that we hadn't included the watt — we weren't seeking federal funding for the Watson Lake bi-fuel project, but we did through the Canadian Electrical Association. The ATCO Group of Companies was participating with them and did submit that project in looking for funding.
>
> What we got back — what I understand we got back from the Federal Government is right now they were looking for projects that were farther along. In fact, they were looking for projects that were shovel ready. So they weren't looking to fund more feasibility studies. They were looking to help make the project — the economics work to get it under construction.
>
> So, to date, we haven't found any funding, but that doesn't mean we're not going to continue to try and access some.[270]

445. The Board is of the view that studies proposed in the Application would reasonably involve an assessment of need, feasibility and policy objectives that could involve government, academics, YEC, municipalities, customers or other stakeholders.

446. The legislative scheme is intended to provide for the regulation of utilities and to provide the Board with various responsibilities in the public interest, including the setting of rates of the utility in the provision of electricity to customers in the Yukon.

447. There is not sufficient evidence for the Board to approve the Renewable and Alternative Energy Feasibility Study proposed in the Application and, without further information, the Board is unable to assess whether or not these studies should be conducted given the need or feasibility of a study to support a renewable and alternative energy project or projects, and whether proposed costs for these studies should be recovered in customer rates. The Board considers that information that should be provided in support for these types of studies or initiatives would include, but is not limited to:

- An analysis of how the study or initiative proposed is related to the utility's statutory requirements of provision of utility service pursuant to the *Public Utilities Act* and its regulations;
- The drivers, need and feasibility for the study or initiative;
- The scope of the study or initiative;
- An expected budget for studies, preliminary reports, and any other primary or secondary reports, as well as a budget for any known implementation costs or an estimate of any expected implementation costs;

[270] Transcript, Volume 3, page 453, lines 11 to 25 and 454 lines 1-15.

- The specific utility projects that are expected to be reviewed or impacted by the proposed initiative(s), as well as corresponding benefits to customers expected as a result of the study and initiative(s); and

- Whether cost-recovery studies and alternative-energy initiatives, energy-saving initiatives, or other initiatives have been explored through grants or other sources of funding, including shareholder funding.

448. The Board considers these studies premature and denies cost recovery or deferral treatment for any costs related to a Renewable and Alternative Energy Feasibility Study and directs AEY to remove forecast expenditures and cost recovery related to its proposals in its compliance filing to this decision.[271]

449. Having made this finding, it is not necessary for the Board to rule on the necessity of a deferral account, the terms of reference, or filing any completed Renewable and Alternative Energy Feasibility Study.

450. Further to the request for two alternative studies as proposed by Mr. Maissan in argument, the Board finds the feasibility and the costs for AEY to undertake these studies has not been examined by the utility or the Board through a proceeding. These recommendations have not received the benefit of being tested by parties during the course of this proceeding. For these reasons, the Board does not support Mr. Maissan's request for AEY to undertake two alternative studies.

12.4.4 Joint Smart Grid Study Deferral Account

451. AEY requested approval for costs related to a Joint Smart Grid Study anticipated to be undertaken in 2017 in partnership with YEC at a cost of $100,000. The study is intended to assess the potential fit and viability of a smart grid in the Yukon. AEY advised that it intends to have the completed smart grid study filed with the Board and made public.[272]

12.4.4.1 Views of interveners

452. Mr. Maissan supported the Board's approval of the $100,000 budget for the proposed smart grid study, citing that there could be significant benefits to ratepayers in the long term if the utilities were to embrace a smart grid approach in the Yukon.[273]

12.4.4.2 Views of the Board

453. The Board considers that such studies are best conducted by industry or funded by government initiatives.

454. There is not sufficient evidence for the Board to approve the Joint Smart Grid Study proposed in the Application and, without further information, the Board is unable to assess whether these studies should be conducted given the need or feasibility of a

[271] For example, at Transcript, Volume 2, page 291, lines 6-10, Mr. Tenney confirmed that ATCO Electric Yukon is one of the members of the Northern consortium, together with three Crown corporations, that fund the research chair in Norther Energy Innovation at Yukon College.
[272] AEY Final Argument, paragraphs 119-122.
[273] JM Final Argument, page 6.

study to support a smart grid project or projects, or whether proposed costs for these studies should be recovered in customer rates.

455. Further, there has been no substantive evidence submitted by parties that provided an indication of any benefits accruing to customers as a result of the proposed study.

456. Similar to its views respecting the Renewable and Alternative Energy Feasibility Study discussed previously, the Board considers a Joint Smart Grid Study to likewise be premature and denies cost recovery or deferral treatment for any costs related to a Joint Smart Grid study. The Board directs AEY to remove forecasted expenditures and cost recovery related to its proposals in its compliance filing to this decision.

457. Having made this finding, it is not necessary for the Board to rule on the necessity of a deferral account, the terms of reference or filing any completed Joint Smart Grid Study.

Appendix A – Summary of Directions

This section is provided for the convenience of readers. In the event of any difference between the directions in this section and those in the main body of the decision, the wording in the main body of the decision shall prevail.

1. The Board notes AEY's submission that, "Had AEY not revised its methodology… AEY's sales would have varied by more than 1.1% when compared to actuals, as of September 2016." Given these submissions on the 2016 and 2017 numbers, the Board understands that the acknowledged differences using the old or new methodologies would not be significant. Considering the above, AEY has not satisfied the Board that its proposed methodology with respect to using three years for regressing data and normalizing HDD, as well as using the 2013 to 2015 growth rates to derive the forecast UPC, should be adopted. The Board accepts AEY's position that 15 or 20 years may be too long of a timeframe to use in calculating energy sales but it is not convinced that three years is correct for regressing data and normalizing HDD. AEY provided testimony during the course of the hearing that ATCO Gas uses a 10-year timeframe for normalizing over the years to represent more current data. Accordingly, the Board directs AEY, in its compliance filing, to refile its sales and revenue forecast, incorporating its prior methodology using a 10-year timeframe for UPC regression and normalizing HDD. ..... Paragraph 40
2. Regarding the existing financial analysts, the Board notes that the reasoning AEY provided for this change in the supervision of these two positions was to have these analysts more tightly tied to northern operations and northern communities, as opposed to the previous reporting structure. AEY added that those positions work solely for AEY. This rationale is not accepted by the Board because it is unclear how this supervisor position, which is to be based in Yellowknife, is to supervise the work of financial assistants who are based in the Yukon and whose work is carried out entirely in the Yukon, when these positions previously reported to a positon that was tied to AEY operations. Further, AEY has not demonstrated that the other primary function (accounts payable and accounts receivable duties) identified for the Supervisor, Business Support Services, cannot be completed by staff at AEY. Additionally, AEY has not provided any explanation of why the supervisory duties of the Supervisor, Business Support Services could not be carried out by any of the existing accounting positions within AEY. Therefore, the Board concludes that the need for the Supervisor, Business Support Services position has not been justified and directs the positon be removed from AEY's complement. ..... Paragraph 76
3. As a result, for out-of-scope employees, the Board awards for 2016, a labour inflation increment of 0.0 percent because out-of-scope employees did not receive inflationary increments. AEY is directed to reflect this change in its compliance filing to this decision. ..... Paragraph 90
4. For these reasons the Board approves a 2017 labour inflation rate for in-scope and out-of-scope employees of 1.9 percent. AEY is directed to reflect this change in its compliance filing to this direction. ..... Paragraph 94

5. The Board notes that AEY provided the May 2016 *Yukon Economic Outlook* in an IR response. In that document, the CPI forecast for Whitehorse for 2016 was 2.0 percent and just under 2.0 percent for 2017. The Board accepts the information provided in the May 2016 *Yukon Economic Outlook* because it is the most up-to-date information on inflation in Yukon on the record. Accordingly, the Board sets the Other Inflation rate for 2016 at 2.0 percent and at 1.9 percent for 2017. AEY is directed to reflect this change in its compliance filing to this decision. ..... Paragraph 105

6. The Board does not accept AEY's submissions that, when considering trends, the total level of O&M costs should be considered or that the review should be limited to those areas with cost variance at the account level. Because of this, the Board believes that a review should be undertaken at the function level for variances in trends, as an inter-relationship between accounts within a function may exist. These inter-relationships may result in misleading trends. Further, at the function level, each function is independent; unless a link is specifically demonstrated, the cost causation in one function does not necessarily lead to cost causation in another function. As a result, the Board directs AEY in its compliance filing and in future GRAs to provide a labour schedule showing total labour costs as well as a breakdown of those labour costs into capital and each of the O&M and A&G functions. This labour schedule is to be provided for each of the test years and the three years prior to the test period. The prior periods will show a labour comparison between forecast and actual. ..... Paragraph 123

7. The Board notes that AEY bases its forecast on historical information, taking into account variance explanations from prior forecasts, and then adds to or reduces the historical amounts based on known upcoming events in the forecast period. However, the Board is concerned about the trends displayed by CW's evidence and finds Attachment 1 to CW-YECL-14 helpful. As noted above, CW evidence is a starting point for further investigation of variance explanations. The Board directs AEY to provide a schedule in future GRAs similar to Attachment 1 to CW-YECL-14, showing labour, fringe and other, comparing actual to approved or forecast levels. The Board also directs that the variance explanations provided in Schedule 5.2 be provided at the labour, fringe and other levels for all future GRAs. ..... Paragraph 124

8. In YUB-YECL-42, AEY was asked to explain the increases in each of the General Accounts (Accounts 88800 and 88900). AEY provided an explanation for Accounts 88800 and 88900 in aggregate but did not provide an explanation for each account individually. In YUB-YECL-42, AEY did provide an explanation for $32,000, which is the total variance. AEY stated in the Application that, "Ongoing operational and administrative activities are based on historic spending requirements which are then adjusted for known changes in work to be completed in the forecast period." However, the Board finds that $14,000 of the increase from 2015 to 2016 has not been sufficiently explained. In this case, using inflation and a three-year average of costs is duplicative as no specific programs or needs have yet been identified. Therefore, the Board directs that the $14,000 be removed from the 2016 forecast value of "Other" for the aggregate of these accounts (88800 and 88900), with $7,000 being removed from Account 88800 and $7,000 being removed from Account 88900. The revised balance

approved by the Board for 2016 “Other” (Account 88800) is $47,000, and the 2017 balance for “Other” (Account 88800) is $44,000. Both balances are subject to changes in the Board-approved inflation rates. AEY is directed to reflect these changes in its compliance filing to this decision..... Paragraph128

9. In YUB-YECL-42, AEY was asked to explain the increases in each of the General Accounts (Accounts 88800 and 88900). AEY provided an explanation for Accounts 88800 and 88900 in aggregate, but did not provide an explanation for each account individually. In YUB-YECL-42, AEY did provide an explanation for $32,000, which is the total variance. AEY stated in the Application that, “Ongoing operational and administrative activities are based on historic spending requirements which are then adjusted for known changes in work to be completed in the forecast period.” However, the Board finds that $14,000 of the increase from 2015 to 2016 has not been sufficiently explained. In this case, using inflation and a three-year average of costs is duplicative as no specific programs or needs have yet been identified. Therefore, the Board directs that the $14,000 be removed from the 2016 forecast value of “Other” for the aggregate of these accounts (88800 and 88900), with $7,000 being removed from Account 88800, and $7,000 being removed from Account 88900. The revised balance approved by the Board for 2016 “Other”, (Account 88900) is $143,000, and the approved 2017 balance for “Other” (Account 88900) is $146,000. Both balances are subject to changes in the Board-approved inflation rates. AEY is directed to reflect these changes in its compliance filing to this decision. ..... Paragraph 130

10. The three-year average (2013-2015) for “Other” for Account 72100 is $1,426,000. The Board finds that it is reasonable to use the three-year average for this account. $1,426,000 is the base amount for this account to which inflation is to be applied. Besides inflation, AEY has not provided an explanation for the increase in “Other” costs between 2015 and 2016 and has not justified a different starting base amount for this account. Therefore, starting from the $1,426,000 base amount, the Board has calculated the 2016 forecast value for this account to be $1,455,000. For 2017, the forecast value is $1,483,000. AEY is directed to reflect these changes in its compliance filing to this decision. ..... Paragraph 134

11. For the purpose of calculating AEY’s depreciation expense for 2016 and 2017, any corrections identified by AEY during the course of the proceeding, or directions made elsewhere in this decision, including those with respect to capital additions, are to be incorporated by AEY. AEY is directed to incorporate these changes in its compliance filing to this decision and its final determination of depreciation expense. ..... Paragraph 163

12. The Board considers that consistent with AEY’s depreciation expense calculations for all other accounts, it is necessary for AEY to incorporate the use of the mid-year convention for Account 493 — Demand Side Management. AEY is directed to revise its depreciation expense calculation for Account 493 — Demand Side Management to reflect a half-year depreciation expense in 2016 for current year capital additions in its compliance filing to this decision.

..... Paragraph 167

13. However, the Board observes that Schedule 7-4, relied on by AEY to support its amortization of accumulated reserve differences amount, disclosed certain negative net salvage percentage information that prompted the clarifications described earlier in this section. The Board considers it would be a simple matter for AEY to have revised Schedule 7-4 to be consistent with the approvals stemming from Board Order 2014-06 and doing so would have avoided unnecessary confusion as to whether the reserve difference amounts complied with Board directions. The Board directs AEY in its future applications, to ensure all supporting schedules filed are consistent with and reflective of Board Orders. ..... Paragraph 172

14. However, in reviewing the AEY response to YUB-YECL-73, the Board notes that actual issue dates for bonds in the years 2011 to 2015 generally occurred before November of the year of issuance. Given that 2016 bonds have been issued before the release of this decision, the Board directs AEY to use the actual cost of debt for 2016 and to reflect this change in its compliance filing to this decision. ..... Paragraph 237

15. As the Board cannot ascertain how AEY determined its credit spread of 1.80 percent, the Board will use the average of credit spreads for the 2011-2016 period. AEY is directed in its compliance filing to this decision to provide an updated table similar to that provided in response to YUB-YECL-73(a) and to update that table to include 2016 actual numbers. In addition, AEY is directed to use the average of the credit spreads for the years 2011-2016, each year given equal weighting, to calculate the credit spread for 2017. The calculated credit spread for 2017 will be added to the updated long Canada bond rate of 2.22 percent and the issue costs of 0.05 percent to determine the cost of debt for 2017.The Board accepts the revised long Canada bond rate proposed by AEY for 2017. AEY is directed to reflect these changes in its compliance filing to this decision. ..... Paragraph 240

16. Considering the above and AEY's submission that it files KPI reports on an annual basis, the Board directs AEY to file on the record of its next GRA, the KPI reports that have been filed with the Board after the record closed in this proceeding. The Board further directs AEY, in its next GRA, to include with the list of improvement projects the reasons for the system deficiency — supported by the KPI filings — that form the basis of the project and the resulting costs. Moreover, AEY is directed to provide a sample report referred to in the quotation above in its next GRA, and to point out and clarify the project expectations — i.e. the expected system performance improvement(s) — that AEY expects will be affirmed by future KPI filings. ..... Paragraph 278

17. Accordingly, the Board directs that all capital costs associated with the end-of-life streetlight conversions be treated as a system cost. ..... Paragraph 292

18. With respect to LED streetlight installations that are not conversions, the Board directs AEY to treat the costs related to new installations or requested conversions as capital costs that attract a full customer contribution in aid of construction. ..... Paragraph 293

19. For the above reasons, the Board is not convinced that the benefits and costs are sufficiently supported to approve the project, and therefore denies the Watson Lake bi-fuel conversion project. AEY is directed to remove the bi-fuel conversion costs from its forecast capital additions in the compliance filing to this decision. ..... Paragraph 354

20. The Board accepts AEY's test period forecast costs because this is an ongoing replacement project. However, because the scope of the project has not been finalized, AEY is directed to provide an updated business case in its next GRA. ..... Paragraph 384

21. If AEY's proposal for alternative 2 (a hybrid system) is explored and is to be implemented, the Board directs AEY to include in its updated business case any revised forecast costs and cost savings. ..... Paragraph 385

22. The Board considers these studies premature and denies cost recovery or deferral treatment for any costs related to a Renewable and Alternative Energy Feasibility study and directs AEY to remove forecast expenditures and cost recovery related to its proposals in its compliance filing to this decision. ..... Paragraph 448

23. Similar to its views respecting the Renewable and Alternative Energy Feasibility Study discussed previously, the Board considers a Joint Smart Grid Study to likewise be premature and denies cost recovery or deferral treatment for any costs related to a Joint Smart Grid study. The Board directs AEY to remove forecast expenditures and cost recovery related to its proposals in its compliance filing to this decision. ..... Paragraph 456

Yukon Utilities Board

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Mandate of the Board

The Yukon Utilities Board (Board) receives its mandate from the Public Utilities Act, its regulations, and Orders in Council. These documents can be found in the “Legislation” section of this website.

What We Do

The Board acts as a rate-setting tribunal for two public utilities.

The Board establishes just and reasonable rates for the provision of electricity by Yukon Energy Corporation (YEC) and by the Yukon Electrical Company Ltd., operating as ATCO Electric Yukon (AEY). YEC is a Crown corporation (publicly owned and operated by the Government of Yukon) and its rates are set by the Board independent from the government.

The Board fulfills its mandate through public hearings. The processes involve reviewing information, researching, consulting with experts, carefully deliberating on information received from the utilities and interveners during hearings. The Board considers the record of each proceeding, provides public dissemination of notices of upcoming Board activities, including rate and facilities applications, and issues its decisions on the Board’s website.

When considering a rate application, the Board reviews the financial requirements of the utility, such as fair return and impacts on the customer. The Board must consider both the sustainability of the utility and the recovery of rates from customers through reasonable charges for utility service.

The Board also requires the public utility to establish, construct, maintain, and operate any reasonable expansion of its existing services and it determines the conditions that may be imposed by a public utility to establish, construct, maintain, and operate an expansion of its existing services.

The Board hears and adjudicates complaints from customers regarding the service provided by YEC and AEY.

What We Don’t Do

The Board does not oversee or manage the daily operations of the utilities. It also does not deal with matters that are not within the Board’s jurisdiction – for example, Yukon Water Board matters.

Utility Rates

The Board strives to ensure that Yukoners have safe electricity service at just and reasonable rates. When applying for an increase in rates all utilities under the YUB's jurisdiction must justify all the components of the revenue requirement to support a requested rate increase. Those costs are considered and analyzed in detail by the Board and include but are not limited to:

• The cost to build, operate, and maintain the utility’s facilities;

• The cost to finance debt incurred from building the utility’s facilities;

• The cost for depreciation and amortization expenses;

• The costs for financing general debt incurred by the utility; and

• Any other costs to provide affordable and reliable service to utility customers.

The Board is a quasi-judicial agency in the Yukon. It ensures independent and objective analyses of proposed rates. The Board operates at arm's length from government and weighs the financial needs of the utility with the needs of ratepayers in its rate-setting decisions. This independence from government processes for approval of rates is fair, open, and transparent.

Utility Facility Projects

The Board has limited oversight over the capital expenditures of Yukon public utilities. The Board may be instructed by the territorial government to provide recommendations about capital projects. For example, in 2014 the Board conducted a comprehensive examination of YEC's proposed liquified natural gas facility at the government's request and submitted the resulting report to the government. However, the Board may order the exclusion of certain capital costs in its calculation of appropriate rates to be charged to Yukon consumers.

Capital development plans figure prominently in the Board's decision-making regarding rate adjustments for both Yukon public utilities. New capital expenditures often require a utility to incur more debt, seeking an increase in consumer rates in order to pay it down. As such, the Board examines the utility's business case to ensure that there is acceptable support for such expenditures.

Regulatory Policy

The Board carries out its mandate based on enabling legislation. The legislation grants the Board significant authority to analyze the accounting practices and financial position and statements of public utilities it regulates.

Through directions specified in its orders, the Board instructs utilities on acceptable practices and procedures. In addition to the enabling legislation, these regulatory policies are aided by the Board's staff and expert advisors.

The Board is further aided by its continued connections with other utility regulators and administrative tribunals. These connections are facilitated by the Board's membership in the Canadian Association of Members of Public Utility Tribunals (CAMPUT). Through these connections, the Board strives to offer innovative regulatory policies and solutions that are consistent with national trends in utility regulation.

Hearing Process

There are two typical methods of review of information through a public hearing. An application can be processed in writing or through an oral hearing. It is at the Board's discretion to decide the appropriate method or venue for adjudicating an application.

All Board hearings proceed in accordance with the Board's Rules of Practice available on the website.

As a quasi-judicial administrative tribunal, the Board maintains a publicly open and accessible hearing room to adjudicate applications.

Written proceedings review all documentary evidence, arguments, and reply arguments that are submitted to the Board from the applicant, interveners, or other third parties.

Oral hearings are held in a public forum accessible to all. A more formal approach to the application is taken, which means that witnesses may be called to testify and be cross-examined by all parties. The hearing proceeds in a relatively uniform manner. It begins with an application from the utility and a public notice informing citizens of the date and time of the hearing as well as the matters of interest set to be examined. A pre-hearing conference may be subsequently held to determine which individuals and groups will act as interveners during the official hearing, with potential interveners applying to the Board. The hearing commences, with examination of the utility taking place at variable times depending on the relative complexity and significance of the matter under scrutiny.

The typical hearing process involves the utility, the Board members, Board counsel and staff, interveners, and any witnesses. Then the parties present their arguments and reply arguments, either orally or in writing.

In both written and oral procedures, the Board's decision is a result of a review of the information available at the time of the close of record for a proceeding. The Board issues its regulatory decisions by way of a Board Order. These decisions are subject to a review and variance process and/or an appeal process. While a news release may be issued, it is up to the media to be informed of the Board's decisions through the website.

Public Participation

As an open and transparent quasi-judicial body, the Board welcomes and encourages public participation in its hearings. Public participation ensures that all issues and perspectives come to the Board's attention in a transparent process. Hearings allow the Board to make a fully informed decision with significant public input. As such, there are several ways for the public to become involved in any public hearing before the Board:

A member of the public may become involved as an intervener. Interveners are individuals or groups who want to take a position on an application before the Board by attending the hearing, providing information and/or evidence, questioning the applicant, and potentially providing a closing statement of position at the end of the hearing. Interveners are expected to

participate actively in the hearing process, including by answering questions posed by the Board and its advisors, as well as the applicant or other parties. An individual or group must apply to become an intervener and their costs to participate may be paid by the applicant if the Board directs costs to be awarded. The interveners must show that they can provide information that will be of benefit to the Board when it enters into deliberations.

At some hearings the Board may make it possible for someone to become involved as a presenter. A presenter is someone who wants to make a statement to the Board about the application being reviewed in a public hearing. Presenters may attend the hearing but are not required to participate in the same way as an intervener. Presenters may be required to pre-register with the Board and they should notify the Board before or at the start of the hearing of their intention to present. Presenters are encouraged to also provide a written copy of their presentations.

A member of the public may become involved as an interested citizen. Any member of the public may attend Board hearings.

For other common questions regarding the hearing process, see the FAQs section of the website.

The Application

The hearing process generally begins when a regulated utility applies to the Board for a decision on a matter within the jurisdiction of the board – for example: rates, facilities, or complaint regarding an electric utility in the Yukon. The hearing may be a written hearing process or an oral hearing.

Applications for rate changes must demonstrate to the Board that a change is appropriate and in the public interest.

Applicants must provide information to support their requests, provide supplemental information when required, and respond to pre-hearing questions from the Board and interveners. Information provided before and during the hearing is examined by the Board is made available to the public online and through the Board office, unless that information is confidential or falls within Yukon's Access to Information and Protection of Privacy Act (ATIPP).

Notice of Public Hearing

The Board is mandated to inform the public about issues to be reviewed at a public hearing. Notices of public hearings are typically published in Yukon newspapers and may be posted within a community impacted by the decision. Notices may also be mailed or electronically transmitted to individuals, groups, or associations that have expressed an interest in the issues.

A notice typically provides the following information:

• A brief explanation of the issues;

• An indication of the potential impact on ratepayers;

• The time, date, and place of a pre-hearing conference and/or the oral hearing; and

• The procedures to be followed during the hearing.

Pre-hearing Conference

Prior to convening an oral public hearing on a rate application from a major utility, the Board may hold a pre-hearing conference. During a pre-hearing conference, the Board may address procedural or substantive issues that are relevant to the hearing. A pre-hearing conference process may include, for example:

(1) The Board seeks to outline the issues to be addressed during the hearing;

(2) The Board identifies interveners and presenters who are both interested and relevant to participate in the pre-hearing conference. While presenters are not required follow the same process that goes into determining

(3) The Board sets a schedule for the exchange of information between the applicant, the Board, interveners, and any other interested parties;

(4) The Board addresses any opening motions that may be made by the applicant, interveners, and any other parties;

(5) As a result of the pre-hearing conference, the Board determines any process that may be necessary for the oral hearing.

Hearing

At the outset of a public hearing, the applicant and interveners are asked to summarize their positions. The application is examined by the Board, its advisers, and any interveners. The applicant and interveners are then given an opportunity to make a final statement at the end of the hearing. Other parties may present at the hearing. When the hearing is over, the Board considers the evidence and a decision (Board Order) is issued. Hearings are recorded and transcribed, and transcripts are made available on the Board's website.
During the course of a hearing, interveners, presenters, and the Board may inquire about a broad range of issues impacting the application under review. The Board is bound by its mandate and enabling legislation, which grants it broad powers with respect to the oversight of public utilities under its jurisdiction.

Board Orders

Board Orders state the Board's decision, reasoning, and directions that the utility must follow. Orders are issued in writing and are made available on the Board's website. Board decisions are legally binding subject to appeal by the Yukon Court of Appeal on questions of law and jurisdiction.

In limited circumstances, the Board will reconsider (review and vary) a decision based on a timely request of the applicant or interested parties, or on the Board's own initiative.

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2023 GENERAL RATE APPLICATION

SUMMARY OF APPLICATION

The Yukon Electrical Company Limited, carrying on business as ATCO Electric Yukon (AEY), has filed an application with the Yukon Utilities Board (Board) requesting an order approving its forecast revenue requirements for the two-year test period 2023 and 2024 (Application). AEY provides electrical services to customers in 19 communities.

AEY is seeking approval of forecast revenue requirements of $60.992 million for 2023 and $68.096 million for 2024. This represents a decrease of $1.211 million for 2023 over revenues from existing rates and riders of $62.203 million (1.9% decrease). For 2024, this represents an increase of $7.914 million over the proposed 2023 revenue requirement (13% increase).

In addition, in its Application, AEY is also seeking approval of an interim refundable rate rider (Rider R) for 2023 of 6.68% (down 1.62% from the existing approved 8.3% for Rider R) for retail and industrial firm rates, effective August 1, 2023. AEY is also requesting a Rider R increase of 5.2% above the current 8.3% for retail and industrial firm rates, effective January 1, 2024.

MESSAGE TO CUSTOMERS

We understand that changes to your utility bill can be concerning and recognize that keeping electricity affordable is vital for both households and businesses alike. We want to take this opportunity to communicate openly and transparently about the reasons behind our proposed rate increase. We acknowledge the financial pressures many of you face and assure you we've carefully considered this decision.

We also recognize that there are questions about our revenue during recent years, even though our rates have not increased. It's important to note that our revenue requirement was set during our General Rate Application in 2017 based on our forecasted business operations. Although our rates have remained unchanged since that time, factors beyond our control have led to higher-than-forecasted revenue. Population growth, increased electricity demand, and expansion in the resource sector have all played a role in the Yukon's revenue growth.

For the past seven years, AEY has successfully maintained stable rates despite the challenges posed by a growing Yukon, a pandemic and hyperinflation. During this time, more than $50 million was invested into Yukon's power grid to ensure safe and reliable power delivery to your homes and businesses. We have carefully managed expenditures and leveraged shared services with ATCO to help keep costs down, and we are proud of our small but mighty team of 55 local Yukoners who keep the lights on and provide customer service across the Yukon. However, with changes in our environment and demand, we find it necessary to file a General Rate Application to ensure continued quality service.

As we move forward, we want to highlight that the proposed rate increase of 5.2% for 2024 comes after a rate decrease of -1.6% in 2023. The proposed rate increase will enable us to:

- **Accommodate Growing Demand**: *With an increasing population and greater energy consumption, we must continue to build and maintain our infrastructure to ensure a reliable and uninterrupted power supply.*
- **Upgrade Aging Infrastructure**: *To ensure the continued reliability and safety of our services, we need to modernize and replace aging components of our system.*

While these are difficult decisions, the investments we are making are vital to maintaining a modern and reliable electric system that meets the needs of Yukoners today and into the future. As we navigate these challenges together, our customers remain top of mind, and our commitment to providing you with safe, reliable, and affordable power is unwavering.

- **Jay Massie, Vice President, Northern Development & Indigenous Relations, ATCO Electric Yukon**

SCHEDULE OF PROCEEDINGS

Pending Ministerial approval, the Board has established the following schedule for this proceeding:

- AEY Procedural Conference - July 27
- Interveners register with the Board - August 4
- Interveners file submissions regarding AEY interim rate request - August 4
- AEY reply to interveners' interim rate submissions - August 10
- IRs to AEY - August 24
- IR Responses from AEY - September 14
- AEY files depreciation parameter information - August 31
- Interveners file any motions regarding IR Responses from AEY - September 21
- IRs to AEY on depreciation parameters - September 26
- IR Responses from AEY on depreciation parameters - October 10
- Intervener evidence - October 19
- IRs on intervener evidence - October 26
- IR Responses on intervener evidence - November 2
- Rebuttal evidence - November 9
- Oral public hearing - November 27-30
- Final argument - December 5
- Reply argument - December 12

An oral public hearing regarding the Application will take place in Whitehorse, Yukon. The venue for the hearing will be determined by the Board at a later date.

INTERVENTIONS

Interveners actively participate in a proceeding, including the filing of evidence (if needed), argument, and reply argument.

Interveners intending to participate in the workshop, hearing, and other process steps are to register in writing with the Board's Executive Secretary by no later than August 4, 2023, indicating the nature of their interest and the issues of interest in relation to the Application. Interveners are also to submit any comments regarding AEY's interim rate request at that time.

To register for AEY's procedural conference as an intervener, member of the public, or organization, please email Beth Rogers at elizabeth.rogers@atco.com.

APPLICATION AVAILABLE

ATCO Electric Yukon 2023 General Rate Application

Business Cases 01-03

Business Cases 04-21

Business Cases 22-38

Business Cases 39-41

The Application and supporting documents are also available on the Board's website at the following URL: https://yukonutilitiesboard.yk.ca/proceedings/atco-electric-yukons-2023-2024-general-rate-application/

CLARIFICATION AND BOARD CONTACT

Persons who wish to intervene or present, and who are uncertain as to the manner in which to proceed, may contact Deana Lemke, Executive Secretary, Yukon Utilities Board, by telephone at (867) 667-5058, in writing at Box 31728, Whitehorse, Yukon Y1A 6L3, by email to yub@utilitiesboard.yk.ca or by fax at (867) 667-5059.

FREQUENTLY ASKED QUESTIONS

- Who regulates ATCO Electric Yukon's rates?
- What is a rate rider?
- What is rider R?
- Why is rider R an interim rider?
- How much is the actual proposed rate increase? What is the fuel adjustment factor?
- Is the proposed rate decrease beginning on August 1 to pay back extra revenue received?
- Has the application for interim rates been approved?
- What is the process for rate changes?
- Why does AEY expect to need higher rates beginning in 2024?
- What infrastructure improvements will a rate increase support?
- Is the rate increase linked to the Yukon government's Our Clean Future plan?
- Is the rate increase linked to the cost of electricity from Yukon Energy?

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Y1A 3T4

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FREQUENTLY ASKED QUESTIONS

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Yukon Utilities Board

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AEY 2023-24 General Rate Application

Application

ATCO Electric Yukon 2023-2024 General Rate Application, July 7, 2023

- 2023-2024 GRA Regulatory Schedules
- Section 01 - Attachment 1.2
- Section 02 - Attachment 2.1
- Section 02 - Attachment 2.2
- Section 11 - Attachment 11.2
- Business Cases 01-03
- Business Cases 04-21
- Business Cases 22-38
- Business Cases 39-41

ATCO Electric Yukon Depreciation Parameter Information Letter, Sept 11, 2023

- 2023-2024 GRA Updated Regulatory Schedules re Depreciation Study
- Attachment 1 - 2022 Depreciation Study Report
- Section 07 - Updated Depreciation
- Section 07 - Updated Depreciation - blackline version

Ministerial Direction

YUB letter to Minister re AEY 2023-24 GRA, July 12, 2023

Letter from Minister re AEY GRA, July 20, 2023

Board Orders

Board Order 2023-13 re AEY GRA proceeding, July 14, 2023

Board Order 2023-14 re AEY GRA proceeding interveners

YEC 2023 General Rate Application
AEY-YEC Rider S Application
AEY 2023-24 General Rate Application
YEC 2022 Low Water Reserve Fund and ERA proceeding
YEC 2021 Low Water Reserve Fund and ERA proceeding
AEY and YEC Rate Rebasing
AEY 2022 Rate Relief Application
YEC Tlingit Homeland Energy EPA
YEC Battery Energy Storage System (BESS) Project proceeding
YEC 2021 General Rate Application
YEC ERA Proceeding and AEY Rider S
YEC-Victoria Gold Power Purchase Agreement
YEC 2017-18 General Rate Application
YECL 2016-17 General Rate Application
YEC-YECL DCF-ERA Proceeding
YEC LNG Project Proceeding
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Board Order 2023-18 re AEY GRA proceeding schedule, Aug. 29, 2023
Board Order 2023-22 re AEY GRA interim rates
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YECL Rate Application

Yukon Energy Corporation 20-Year Resource Plan

YEC-Minto Power Purchase Agreement

Carmacks-Stewart Transmission Project (CSTP) - Part 3 Review

Correspondence and Other Information

Distribution list for AEY GRA
AEY letter to YUB re process steps, July 17, 2023
YUB reply to AEY re proceeding schedule, July 18, 2023
Frank Bachmier letter re presenting at AEY GRA, Jul 27, 2023
YEC comments re AEY interim rate request, Aug 4, 2023
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John Maissan response Process Schedule, Aug 16, 2023
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Yukon NDP response re Process Schedule, Aug. 17, 2023
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Comments

Letter from Frank Bachmier re presenting at AEY GRA, July 27, 2023
CFIB letter re ATCO Electric Yukon Rate Hike, July 31, 2023

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Yukon Conservation Society application for intervener stauts, July 21, 2023
YEC application for intervener status, July 31, 2023
John Maissan request for intervener status, July 31, 2023
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UCG IRs, Sept. 6, 2023

John Maissan IRs, Sept. 6, 2023

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Florian Boulais IRs, Sept. 6, 2023

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John Maissan Round 2 IRs, Oct. 10, 2023

UCG Round 2 IRs, Oct. 10, 2023

Responses to Information Requests

AEY Consolidated IR Responses, Sept. 28, 2023

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AEY IR Responses to YUB - Part 2 of 2

- 001(f) Attachment
- 001(h) Attachment
- 002(b) Attachment
- 045(a) Attachment
- 046(a) Attachment
- 067(f) Attachment
- 070(b) Attachment

AEY IR Responses to YUB-65 and YUB-66

AEY IR Responses to UCG Part 1 of 9, Sept. 28, 2023

- 003(d) Attachment
- 007(a) Attachment
- 025 Attachment
- 026(a) Attachment
- 027(a) Attachment
- 031(a) Attachment
- 050(b) Attachment
- 050(f) Attachment
- 053(e) Attachment
- 054(d) Attachment
- 055(1) Attachment
- 101(a) Attachment

AEY IR Responses to UCG Part 2 of 9, Sept. 28, 2023

AEY IR Responses to UCG Part 3 of 9, Sept. 28, 2023

AEY IR Responses to UCG Part 4 of 9, Sept. 28, 2023

AEY IR Responses to UCG Part 5 of 9, Sept. 28, 2023

AEY IR Responses to UCG Part 6 of 9, Sept. 28, 2023

AEY IR Responses to UCG Part 7 of 9, Sept. 28, 2023

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AEY IR Responses to UCG Part 9 of 9, Sept. 28, 2023

AEY IR Responses to John Maissan, Sept. 28, 2023
- 004(b) Attachment
- 025(a) Attachment

AEY IR Responses to Nathaniel Yee, Sept. 28, 2023

AEY IR Responses to Yukon NDP, Sept. 28, 2023
- 002(a) Attachment

AEY IR Responses to Florian Boulais, Sept. 28, 2023

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Yukon Economic Outlook

May 2016

Yukon
Economic Development

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Yukon Government
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ECONOMIC FORECASTING AND RISK

This forecast examines near-term expectations for Yukon's economy, focusing on the anticipated performance of key economic indicators and sectors.

As with all forecasts, the results are dependent on the information available at the time of forecast completion and key assumptions incorporated into the forecast. Assumptions such as the level and timing of mining development activity, estimates of annual mineral production and estimates of construction spending, can all impact the forecast results, particularly for an economy as small as Yukon's. While best efforts are made to develop assumptions that reasonably capture Yukon's potential economic performance in the near-term, there is always a degree of risk and uncertainty associated with these assumptions, and ultimately the forecast results. Key examples of potential risks to the forecast are noted below:

- Global Economic Performance – The performance of Yukon's economy is tied to the performance of other key economies, such as the U.S. and China, and to the global economy as a whole. Demand for Yukon goods and services, including minerals and local tourism activities, can depend very much on what is happening outside of the territory.

- Metal Prices – Metal prices are a key determinant of mining activity (exploration, development and production) and are determined on the global market. Projections from a variety of forecasters were considered in preparing this forecast.

- Energy Prices – Energy prices are also determined on the world market. For Yukon, the price of oil can influence economic activity particularly in how it can impact mining sector activity (fuel for project operations and equipment) as well as impact tourism activities (fuel for travelers' vehicles). The price of fuel also influences the cost of Yukon construction activities and the cost of goods in Yukon as the majority of goods purchased locally are transported from outside the territory.

- Exchange Rates – The value of the Canadian dollar versus other currencies can impact spending decisions by tourists and also investment decisions by resource-based companies. A strengthening or weakening dollar may affect this forecast.

- Interest Rates – Lower interest rates can contribute to increased investment as the cost of borrowing is reduced. Alternatively, increasing interest rates increase the cost of borrowing and can dampen investment spending. The cost of borrowing in Canada has been low for a prolonged period, with the Bank of Canada's daily overnight target for the bank rate not exceeding 1.0 per cent since January 19, 2009. This forecast assumes that interest rates will remain relatively low for the foreseeable future.

Finally, circumstances that impact forecast assumptions can change rapidly, resulting in the forecast becoming dated. Yukon is an example of a small economy that can be rapidly influenced by outside events. Information in this forecast is current to May 12, 2016 which allows for the inclusion of Statistics Canada's preliminary GDP estimates for 2015.

HIGHLIGHTS FOR 2015

- Statistics Canada preliminary estimates for Yukon real Gross Domestic Product (GDP) for 2015, released May 12, 2016, have Yukon's real GDP by Industry at $2.177 billion in 2015, down 3.8 per cent from $2.264 billion in 2014, representing the third consecutive annual contraction.
    - The primary contributor to the contraction was lower mineral production, the result of weak mineral prices and an ongoing slowdown in the global mining industry.
- Yukon's June 2015 population of 37,343 up slightly from the June 2014 figure of 37,251, marking the 12th consecutive year of growth.
- Yukon's labour market was impacted by the weaker economic activity:
    - Total employment averaged 19,400, down 400 from 2014.
    - The labour force averaged 20,700, unchanged from 2014.
    - Average unemployment rate of 6.3 per cent, up from 4.3 per cent in 2014.
- Statistics Canada data for retail sales reports Yukon sales of over $692 million, up 4.7 per cent from 2014.
- Border crossings are reported as falling by 4.1 per cent, to 327,778.
    - Concerns have been raised about the accuracy of the 2015 data as anecdotal information indicates that 2015 was a good year for local tourism operators.
- At $117.7 million, the value of building permits in 2015 was down 9.7 per cent from $130.5 million in 2014.
    - Permit value was down in all areas, with the exception of government/institutional permits. Biggest losses were noted in residential permits.
- A modest decrease in the Consumer Price Index (CPI) was experienced in Whitehorse, down 0.2 per cent in 2015.

FORECAST FOR 2016

- The forecast for real GDP in 2016 is for growth of 2.8 per cent.
    - Growth in 2016 is primarily related to an expected increase in mineral production at the Minto mine with the beginning of stripping of the Minto North pit.
- Modest population growth is expected, with gains of 0.7 per cent in 2016.
- The number of employed and the size of the labour force are both expected to increase slightly to 19,500 and 20,900, respectively. The unemployment rate in 2016 is expected to rise to 6.6 per cent.
- Following reported strong gains in 2015, retail sales are expected to post modest growth in 2016.
- Early indications are that 2016 will be a positive year for Yukon tourism.
- Building permit value is expected to be up slightly from the 2016 level.
- Following deflation in 2015, the Whitehorse CPI is expected to grow by 2.0 per cent in 2016.

PRELIMINARY FORECAST FOR 2017

- Early expectations for 2017 are for Yukon's real GDP to fall by 5.7 per cent.
  - Lower year-over-year mineral production, associated with the expected shutdown of the Minto mine, is the primary contributor to the contraction.
- Population growth of 0.3 per cent.
- Employment and the labour force are expected to post modest gains, with employment increasing to over 19,600 and the labour force increasing to almost 21,000. The unemployment rate in 2017 is expected to fall slightly to 6.3 per cent.
- Retail sales are expected to grow to over $700 million.
- A modest increase in building permit value is expected, growing to about $125 million.
- Growth in the Whitehorse CPI is expected to be just under 2.0 per cent.

GLOBAL, U.S. AND CANADIAN OUTLOOK

The April 2016 *World Economic Outlook* prepared by the International Monetary Fund (IMF) notes that global growth prospects have worsened since their previous forecast release (January 2016).

The current IMF forecast is for global growth of 3.2 per cent for 2016, slightly higher than the 2015 estimate of 3.1 per cent, but below the IMF's January 2016 forecast of 3.4 per cent. Looking to 2017, the IMF is projecting stronger global growth of 3.5 per cent, down from the January 2016 forecast of 3.6 per cent.

The strengthening recovery in 2017 is noted as being driven primarily by emerging market and developing economies, as conditions in stressed economies start to gradually normalize. While growth is expected to pick-up, the IMF notes that uncertainty has increased, and risks of possible weaker growth were becoming more tangible. [1]

Even with the growth rate declining for the fifth consecutive year in 2015, growth in emerging market and developing economies continues to outpace that of growth in advanced economies. The IMF is forecasting that growth in emerging and market and developing economies will continue to account for the lion's share of projected world growth in 2016 and 2017. Following growth of 4.0 per cent in 2015, the IMF is forecasting growth of 4.1 per cent in 2016, to be followed by stronger growth of 4.6 per cent in 2017.

While continuing to grow, prospects across emerging market and developing countries remain uneven and generally weaker than over the past two decades.[2] The IMF's April Outlook noted in particular that a number of large emerging markets, including Brazil and Russia, are still in the midst of recessions. Others, including several oil-exporting countries, were also noted as dealing with weaker terms of trade and tighter external financial conditions.[3] Declining investment growth in emerging market economies was also noted as a contributing factor to recent weaker performance.

China's economy remains in a period of transition, moving to development of services and retail in support of its domestic demand from an economy supported substantially through

manufacturing activities and large scale industrial development. Even with the recent slowdown, China, along with India, will continue to lead the way for emerging market countries. Following estimated growth of 6.9 per cent in 2015, China's economy is expected to grow 6.5 per cent and 6.2 per cent over the next two years. Following growth of 7.3 per cent in 2015, India is forecast to post gains of 7.5 per cent in both 2016 and 2017.[4]

Following estimated growth of 1.9 per cent in 2015, advanced economies are forecast to grow by 1.9 and 2.0 per cent annually over the next two years. U.S. growth is expected to remain the primary driver of growth in advanced economies with U.S. growth rates in both 2016 and 2017 exceeding the overall growth rates of advanced economies.

Stronger housing and labour markets and favourable financial conditions continue to support the U.S. economy. Significant employment gains were noted in 2015, with an average of 221,000 jobs added on a monthly basis.[5] Improving labour income and lower gasoline prices have supported private domestic demand, as reflected in near-record-high vehicle sales, robust residential construction and strong business investment outside the commodity-related sectors.[6] The current IMF forecast has U.S. growth in the near-term approximating recent growth rates. Following estimated growth of 2.4 per cent in 2015, the forecast calls for growth of 2.4 and 2.5 per cent in both 2016 and 2017.

Recently, Canada's economy has underperformed the U.S. economy and expectations are that this will continue in the near-term. Much of the recent weakness is attributed to weaker commodity prices, particularly oil prices, which due to oversupply in the global market has declined significantly in the last 18-20 months, falling below $30 per barrel for a time in early 2016. Prices for many key mineral exports are also down substantially from recent levels which has contributed to mine closures, layoffs, reduction in mineral exports and lower levels of investment in Canada's mining sector. Evidence of the recent poor performance of oil and mineral prices can be seen in estimates of economic performance and expectations for performance in the near-term. The IMF is estimated that Canada's economy only grew by 1.2 per cent in 2015. Expectations for slightly stronger growth is noted by the IMF for 2016 and 2017, with gains of 1.5 per cent and 1.9 per cent, respectively. The April 2016 forecast represents a downgrade from the January 2016 forecast of 1.7 per cent and 2.1 per cent for 2016 and 2017 respectively.

The Bank of Canada is also forecasting relatively weak economic growth for Canada in 2016, to be followed by improved performance in 2017. The April 2016 *Monetary Policy Report* includes real GDP growth forecasts of 1.7 per cent in 2016 and 2.3 per cent in 2017. While the Bank noted that global and domestic developments, including the economy's adjustment to the ongoing weakness in oil prices, would have resulted in a modest downgrade of its outlook for 2016 and 2017, fiscal measures announced in the March Federal budget will have a notable positive impact.[7]

Resource extraction activities continue to be a significant contributor to Canada's economy, and growth prospects for the country are inherently linked to the performance of commodity prices. The weakness in mineral prices that began in 2014 became more prominent in 2015 and has continued into 2016. Prices for key commodities such as gold, silver and copper recently touched lows not seen in five to six years. Concerns about global demand, especially declining demand from China, as well as increases in supply that followed the most recent mining investment boom, continue to contribute to uncertainty about a recovery in mineral prices.

Even more of a downward drag on Canada's economy has been the rapid decline in oil prices. A glut of supply, weaker demand from China and Iranian oil hitting the global market with the lifting of Nuclear related sanctions have all contributed to weakness in oil prices. High crude oil inventories held by the U.S. are also working to keep oil prices low, near record levels at the time of writing. The outlook for oil prices remains poor, with many forecasters expecting prices to remain relatively low throughout 2016, before a minor recovery in 2017. At the time of writing, BMO Capital Markets is calling for oil prices to average US$37 per barrel in 2016, down from US$48.69 in 2015, and US$93.26 just two years ago (2014).[8] At US$37 per barrel, the price of oil would be the lowest since 2003 when it averaged just over US$31 per barrel.

After averaging US$4.39 per MMBTU[9] (Henry Hub) in 2014, the highest annual average since 2010, natural gas prices declined significantly in 2015, averaging about US$2.63 per MMBTU. Natural gas prices are expected to perform better than oil prices in the near-term, but remain well below recent highs. BMO Capital Markets is forecasting Henry Hub Natural Gas prices to fall to US$2.25 per MMBTU in 2016 before increasing to US$3.20 per MMBTU in 2017.

Future growth prospects for Canada are also tied to interest rates. After being pegged at 1.0 per cent since September 2010, the Bank of Canada surprised most analysts in January 2015 when it lowered the overnight rate to 0.75 per cent, and then lowered it further to 0.5 per cent in July 2015. Given the weaker outlook for Canada's economy Canadian interest rates are expected to remain low throughout 2016 and likely into 2017. At its most recent rate announcement on April 13, 2016, the Bank of Canada maintained the overnight rate at 0.5 per cent, opting to continue to keep the cost of borrowing relatively low. The next interest rate announcement for the Bank of Canada is scheduled for May 25, 2016.

Outlook for Global, U.S. and Canadian Economies

The IMF's April 2016 update to the World Economic Outlook includes the following forecasts:

- Global Growth: 3.2 per cent (2016) and 3.5 per cent (2017);
- U.S. Growth: 2.4 per cent (2016) and 2.5 per cent (2017); and
- Canadian Growth: 1.5 per cent (2016) and 1.9 per cent (2017).

RECENT PERFORMANCE AND SHORT-TERM OUTLOOK

PART A: ECONOMIC INDICATORS

GROSS DOMESTIC PRODUCT (GDP)

Preliminary data released by Statistics Canada in May 2016 estimates that Yukon's real GDP by industry in 2015 contracted by 3.8 per cent to $2.177 billion. The decline in 2015 represented a third consecutive year of contraction for the territory.

Among the provinces and territories, Yukon 2015 performance ranked only ahead of Alberta which saw a contraction of 4.0 per cent. Prior to 2013, Yukon's real GDP had posted nine straight years of growth.

Weakness in the mining sector continued to weigh on Yukon's economy in 2015, resulting in a substantial decline in mineral production in 2015. Suspension of production from the Wolverine mine in January 2015 saw mineral production come in well below the 2014 level. A 43 per cent decline in the mining quarrying and oil and gas extraction component of GDP was the primary contributor to the 2015 decline.

While the percentage contribution of mining in 2015 falls well below the high of abour 22 per cent noted in 2012, figure 3[10] shows the current contribution of mining related activities still remains well above estimates of a decade ago. At over 11 per cent of total real GDP the 2015 contribution of mining, quarrying and oil & gas extraction is more than double the contribution noted in 2005.

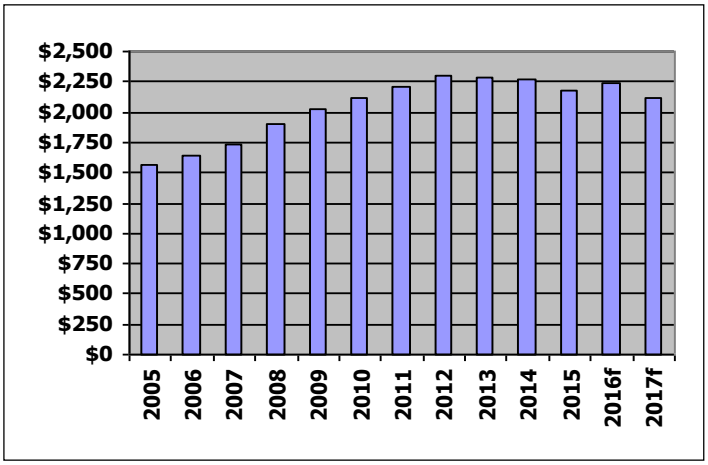


Figure 1 – Real GDP by Industry (2007$ millions)
Source: Department of Economic Development; Statistics Canada

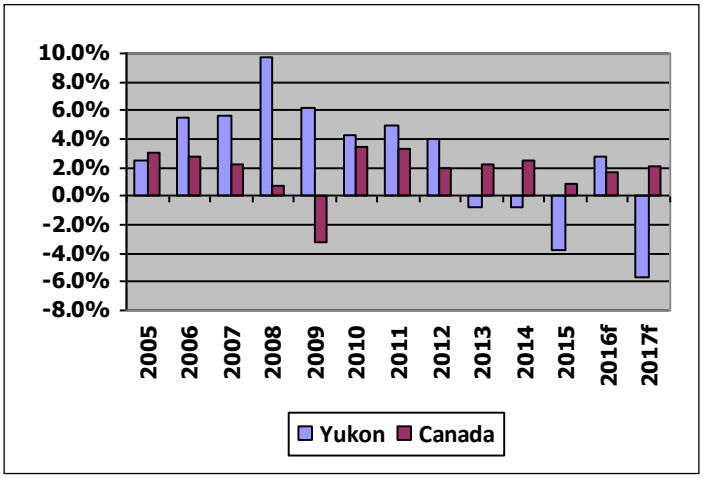


Figure 2 – Real GDP by Industry – Annual Growth Rate
Source: Department of Economic Development; Statistics Canada; International Monetary Fund

Yukon's real GDP is expected to post gains in 2016, with growth primarily related to expectations of increased mineral production as the inclusion of production from its Minto North pit contributes to gains in Minto production. Overall, Yukon's real GDP is forecast to grow 2.8 per cent in 2016.

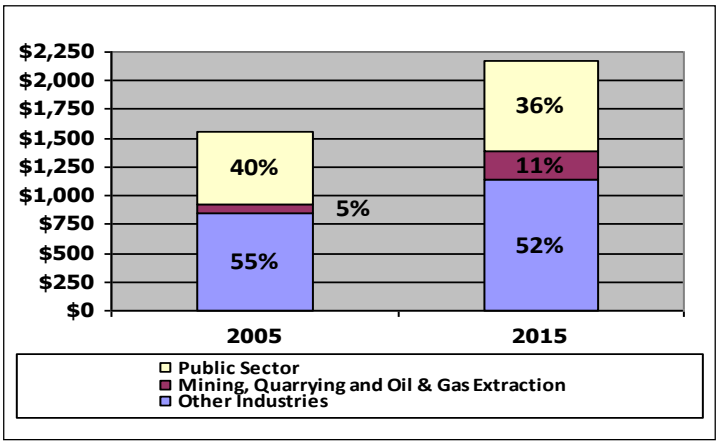


Figure 3 – Real GDP by Industry (2007$ millions)
Source: Department of Economic Development; Statistics Canada

Yukon's economic performance is linked to the performance of the global mineral industry. Expectations are for mineral prices to remain depressed for the medium-term, which will weigh on Yukon growth prospects beyond 2016. With Capstone Mining Corporation already noting that they plan to temporarily shut the Minto mine in the second quarter of 2017, the preliminary forecast for 2017 is for a contraction of 5.7 per cent.

Outlook for GDP

- Preliminary estimates from Statistics Canada note a third straight decline in Yukon's real GDP by industry, with the 2015 estimate of $2.177 representing a 3.8 per cent decline from $2.264 in 2014.
- Anticipated growth in mineral production in 2016 is expected to contribute to real GDP gains, with growth of 2.8 per cent forecasted for 2016.
- The preliminary forecast for 2017 is for a real GDP decline of 5.7 per cent, with the contraction related primarily to lower mineral production.

POPULATION

Population is estimated to have grown for the 12th consecutive year in 2015. Annual population in 2015, as represented by the June 2015 figure, was 37,343, up slightly from 37,251 in June 2014.

Whitehorse[11] – at 28,872 – accounted for over 77 per cent of Yukon's total population in June 2015. Serving as Yukon's primary goods and services hub, population gains in Whitehorse have accounted for the majority of Yukon's recent population growth.

Of the remaining Yukon communities, only two had populations above 1,000 in 2015, Dawson City at 2,067 and Watson Lake at 1,469.

Expectations for the near-term are for modest population gains in the next two years. The current forecast is for population to grow by 0.7 per cent in 2016, followed by growth of 0.3 per cent in 2017. The population forecast represents in part the generally weaker outlook for Yukon's economy. Ongoing weakness in the mining sector and the local economy also presents downside risk to the near-term outlook for population.

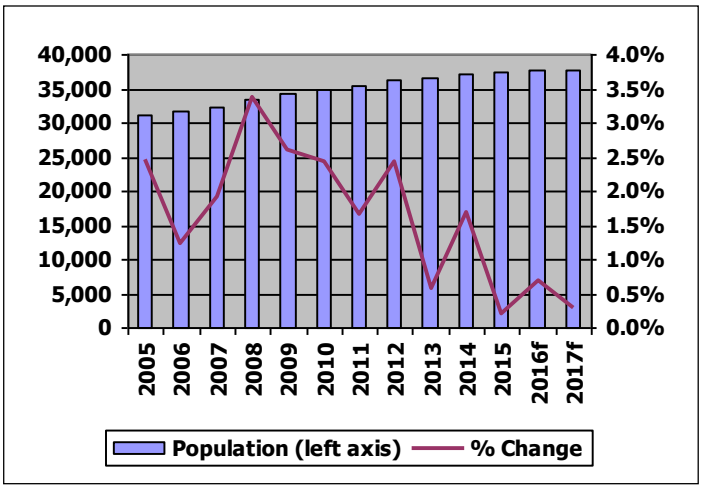


Figure 4 – Yukon Population (June)

Source: Department of Economic Development; Yukon Bureau of Statistics

Outlook for Population

- Following growth of 0.2 per cent in 2015, gains in population in the near-term are expected to remain modest with growth of 0.7 per cent in 2016 and 0.3 per cent in 2017.

LABOUR MARKET

Yukon's labour market has generally performed well in recent years, with Yukon's unemployment rate tracking below the national average for over a decade (see Figure 6). During this time, record levels of employment and labour force have been recorded, with Yukon's unemployment rate amongst the lowest in the country.

Even in light of the struggles for the local economy in 2013 and 2014, Yukon's labour market proved resilient, with notable growth in the labour market and employment, and an unemployment rate that fell to 4.3 per cent.

Signs of weakness in the local labour market were noted in 2015. While Yukon's labour force remained unchanged at 20,700 in 2015, employment fell to 19,400, down 400 from the record level of 19,800 noted in 2014. While down, the number of people employed in Yukon in 2015 was the second highest on record. With no change in the labour force and falling employment, Yukon's unemployment rate increased to 6.3 per cent, up markedly from 4.3 per cent in 2014.

The outlook for Yukon's labour market in 2016 is for marginal growth in both the labour force and employment, with an increase in the unemployment rate for a second consecutive year. With expected GDP growth in 2016 stemming primarily from an increase in mineral production from a mine that is already in production, there is no expectation that this will have a positive impact on local employment. In fact, with Capstone Mining Corporation announcing that it will be ceasing underground mining operations in 2016, local employment losses at the mine are anticipated.

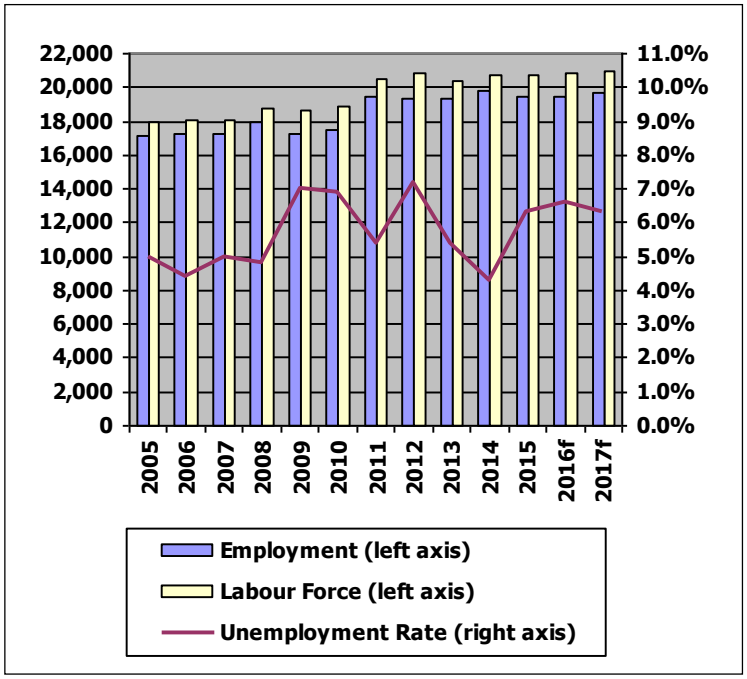


Figure 5 – Key Labour Market Statistics
Source: Department of Economic Development; Statistics Canada

Employment in 2016 is expected to see a modest increase averaging near 19,500. The labour force is also expected to grow, increasing to almost 20,900. A further increase in the unemployment rate is forecasted, increasing to 6.6 per cent in 2016.

Preliminary expectations are for little change in Yukon's labour market in 2017. The number of people employed and the size of the labour force are expected to see minor increases. With the gains in employment to exceed those of the labour force Yukon's unemployment rate is expected to decline slightly to 6.3 per cent.

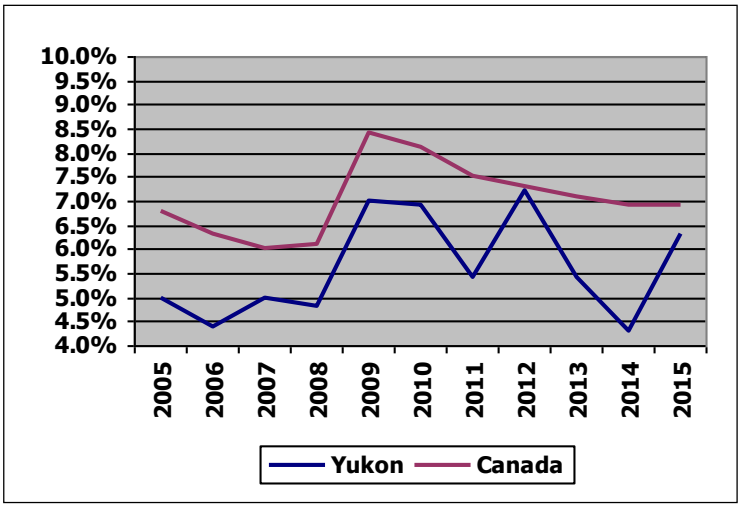


Figure 6 – Unemployment Rate – Yukon vs. Canada
Source: Department of Economic Development; Statistics Canada

Outlook for the Labour Market

- Weaker economic outlook reflected in near-term expectations for the labour market.
  - Average employment is expected to grow slightly in 2016 and 2017.
  - Average labour force expected to increase modestly in 2016 and 2017.
  - Yukon's unemployment rate in 2016 is expected to increase, before a slight decrease in 2017.

CONSUMER PRICE INDEX

Inflation in Whitehorse, as measured by the change in the Whitehorse Consumer Price Index (CPI)[12], has been low in recent years falling below 2.0 per cent over the 2013-2015 period.

The Whitehorse CPI actually declined in 2015, falling 0.2 per cent below the 2014 level. Nationally, CPI posted an increase of 1.1 per cent.

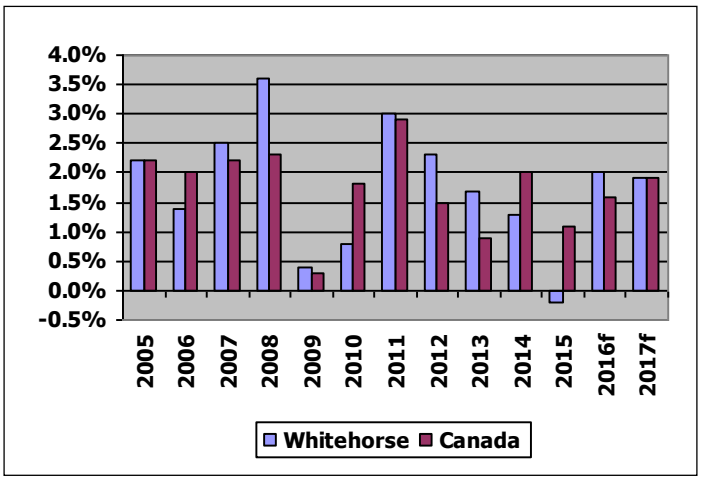


Figure 7 – Change in CPI: Whitehorse vs. Canada
Source: Department of Economic Development; Statistics Canada; BMO Capital Markets

Lower oil prices weighed on gasoline prices in 2015, with average gasoline prices in Whitehorse down about 16 per cent from 2014. Lower gasoline prices were reflected in the Gasoline component of CPI, down 15.7 per cent and the Transportation component, down 3.2 per cent.

The Shelter component of CPI was also down in 2015, 2.4 per cent lower than the average 2014 figure. Lower prices for home heating fuel in Whitehorse, down almost 20 per cent from 2014, helped to contribute to lower shelter costs in 2015.

CPI Components that posted notable price increases in 2015 included Clothing and Footwear (3.0 per cent), Alcoholic Beverages and Tobacco Products (2.4 per cent), Food (2.2 per cent) and Recreation, Education and Reading (2.2 per cent).

Current expectations are for prices to pick up steam in 2016, growing 2.0 per cent. Contributing to this increase is the expectation of higher food prices, partly due to the expectation of the weakness in the Canadian dollar to persist throughout 2016, as well as the expectation that fuel prices might begin to increase later in the year.

Beyond 2016 prices are expected to continue to increase, with a further increase of 1.9 per cent in the Whitehorse CPI growth in 2017.

Outlook for CPI

- Following price deflation of 0.2 per cent in 2015, the Whitehorse CPI is expected to increase by 2.0 per cent in 2016 and 1.9 per cent in 2017.

PART B: ECONOMIC SECTORS

MINING

Weak mineral prices continue to weigh on the global mining sector, contributing to mine closures, layoffs, project delays, and generally lower levels of spending.

Not surprisingly, Yukon's mining sector has also been negatively impacted with two mine closures since the beginning of 2013 and far lower levels of exploration and development spending than what has been experienced in recent history.

While Yukon's world-class geology does position the territory favorably for future growth in the mining sector, the relatively poor outlook for mineral prices has created substantial uncertainty for exploration, development and production activities going forward.

MINERAL EXPLORATION

A weaker environment for mineral prices prevailed throughout 2015 contributing to an inability of many mining companies, particularly junior mining companies, to raise capital to finance exploration activities. A number of operators also took steps to lower costs in response to lower prices.

Yukon, like many jurisdictions, saw less activity related to exploration and lower levels of spending. With much of the exploration work undertaken in the territory completed by junior mining companies, the difficulty of juniors to raise money has seen exploration expenditures fall off substantially. Natural Resources Canada's (NRCAN) latest *Survey of Mineral Exploration, Deposit Appraisal and Mine Complex Development Expenditures*, released in February 2016, estimates exploration spending[13] fell to $73.3 million in 2015, down from $107.1 million, spending in 2015 and well below spending of $331.7 million in 2011 and $233.2 million in 2012.

Following a period where a much greater proportion of exploration-related spending was associated with "exploration"[14] activities, recent years have seen more spending in the areas of deposit appraisal[15]. NRCAN's spending estimate for 2015 includes an estimated $45.3 million related to expenditures on deposit appraisal and the remaining $28.0 million associated with exploration. At $45.3 million, spending on deposit appraisal accounted for almost 62 per cent of the total spending figure, far higher than during the last exploration boom which saw deposit

appraisal spending of $40.7 million (26 per cent), $76.0 million (23 per cent) and $52.9 million (23 per cent) in 2010, 2011 and 2012, respectively.

Estimates from the Department of Energy, Mines & Resources (EMR) have exploration expenditures of about $65 million in 2015, down from EMR's estimate of $80 million in 2014. EMR exploration spending estimates are generally lower than NRCAN estimates as the NRCAN spending numbers include such expenditures as related road development and environmental baseline work. The EMR number is more representative of spending on pure exploration work such as drilling and geochemical. Differences between EMR and NRCAN exploration spending numbers can also occur because the NRCAN numbers are based on a survey completed early in the year while EMR numbers are based on announced company budgets.

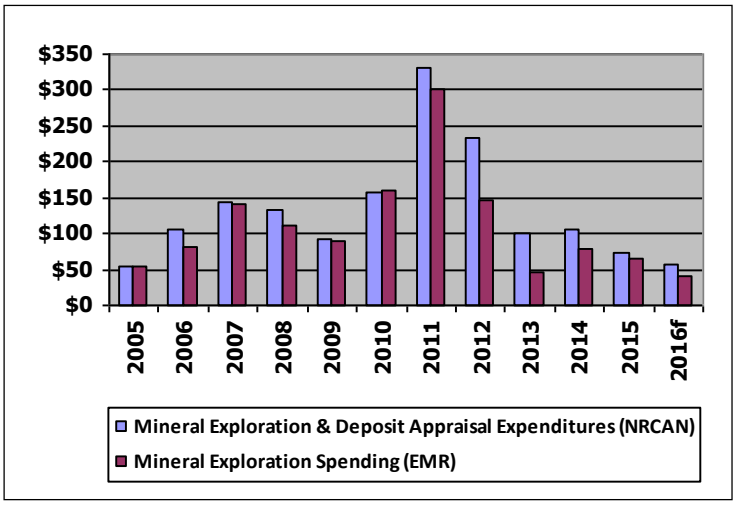


Figure 8 – Mineral Exploration Expenditures ($ millions)
Source: Department of Economic Development; Natural Resources Canada

The near-term outlook for the global mining sector remains poor, as global mining prices are expected to remain well below recent highs. Mining companies are anticipated to continue to take steps to keep costs low with spending on exploration and development activities remaining relatively low. Current estimates from EMR have exploration spending in 2016 falling to approximately $40 million, with spending by BMC Minerals Ltd. at its Kudz Ze Kayah property expected to account for about half of the total spending. Results of NRCAN's latest spending intentions survey have exploration related expenditures in 2016 at $56.4 million, also down from its 2015 spending estimate.

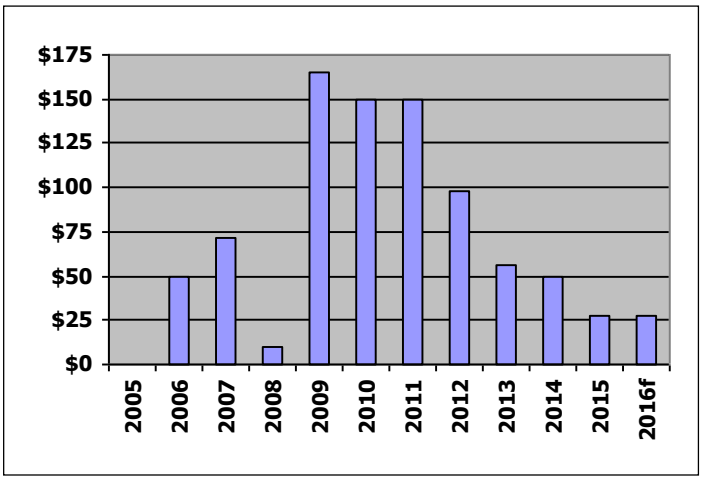


Figure 9 – Mineral Development Expenditures ($ millions)
Source: Department of Economic Development; Department of Energy, Mines & Resources

MINING DEVELOPMENT

With no mines in development, spending over the past three years has fallen well under recent highs.

Development spending in 2015 was estimated at just under $30 million, down from about $50 million in 2014. Almost two-thirds of the 2015 spending estimate is associated with expenditures at the Minto mine related to the continued expansion of underground mining.

EMR's development expenditure forecast for 2016 has spending at slightly below the 2015 estimate.

MINERAL PRODUCTION

After approaching $500 million in 2012, the value of mineral production has fallen in every year since. Closures of the Bellekeno mine in September 2013 and the Wolverine mine in January 2015 account for the majority of the recent declines.

The notable decline in the value of mineral production in 2015 was the result of both lower production and substantially lower year-over-year prices. The closure of the Wolverine mine in January 2015 accounted for the majority of the decline in mineral production. As illustrated in Figure 10, after approaching $500 million in 2012, the value of mineral production in 2015 fell below $250 million.

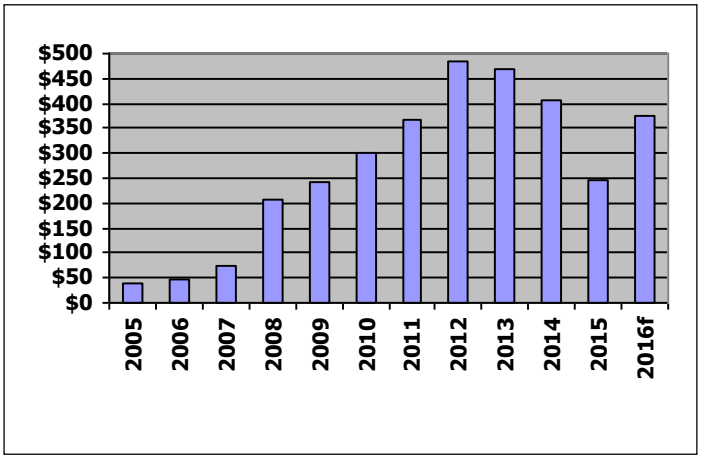


Figure 10 – Value of Mineral Production ($ millions)
Source: Department of Economic Development; Natural Resources Canada

Looking to 2016, expectations are for prices to remain weak and to fall below 2015 levels. Production on the other hand is expected to increase markedly with Capstone Mining Corporation's production guidance[16] for 2016 indicating production well above the 2015 level. The current outlook for the value of mineral production is for growth of over 50 per cent to about $375 million.

Placer mining continues to be a positive story for Yukon's mining sector. Over the past four years, the value of placer production has averaged almost $70 million, making it a significant contributor to Yukon's total value of mining. For the period 2013 to 2015, placer gold production has averaged almost 59,000 crude ounces. Placer gold production in 2016 is expected to be similar to the over 62,000 crude ounces produced in 2015.

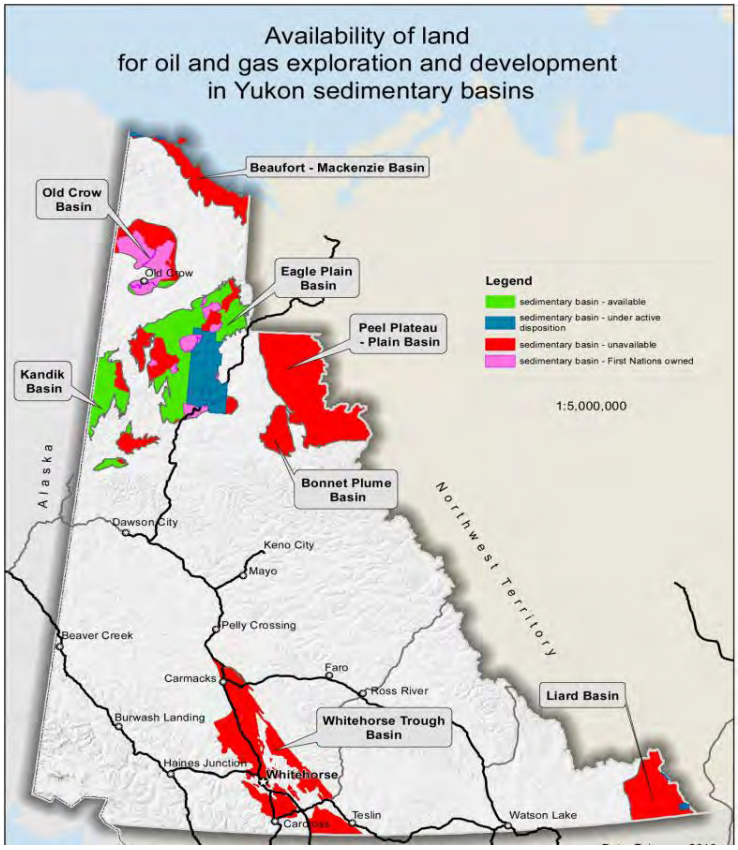
Beyond 2016, further headwinds for Yukon's mining sector are anticipated. The outlook for mineral prices remains poor which is expected to continue to dampen mining-related spending. With the January 2015 announcement by Capstone Mining Corporation that they plan to temporarily cease operations of the Minto mine in early 2017, the value of mineral production will likely fall to the lowest level since 2008 which was the first full year of Minto production.

Outlook for Mining

- Exploration and development spending in 2016 expected to fall below 2015 levels.
- Increased Minto production is expected to contribute to gains in the value of mineral production in 2016, but the planned temporary shutdown of the Minto mine in early 2017 will significantly impact next year's mineral production.

OIL & GAS

Yukon is home to significant hydrocarbon resources, both onshore and offshore. Yukon's onshore sedimentary basins contain an estimated 14.77 trillion cubic feet (Tcf) of conventional natural gas and 663 million barrels (MMbbls) of conventional oil. Offshore conventional resources in the Beaufort Sea include an additional estimated 40 Tcf of natural gas and 4,500 MMbbls of oil. Yukon also has the potential to host significant unconventional oil and gas resources although further assessment work is required.



Since production ceased at the Kotaneelee field in September 2012, there has been no commercial hydrocarbon production in Yukon. EFL Overseas Inc. (EFLO) has a 54 per cent working interest in the Kotaneelee field, and had been interested in workovers of existing wells. At this time EFLO has no plans to start this work in the foreseeable future.

Interest has also been shown in the hydrocarbon potential of the Eagle Plain Basin in Northern Yukon. Supported by investment from China National Offshore Oil Corporation (CNOOC), Northern Cross (Yukon) Limited has spent more than $100 million since their current exploration program began in late 2011.[17] Northern Cross' multi-well exploration program that was submitted to YESAB in 2014, proposes to drill and conduct extended flow tests on up to 20 exploratory oil and gas wells in the area that it completed a 3D seismic program in early 2014. Wells are planned to be drilled and tested from December to mid-April and from May to October, over a period of eight years.[18] These wells would be in addition to the four wells drilled in 2012 and 2013. Citing concerns about the uncertainty of the drilling program's impacts on the Porcupine Caribou Herd, YESAB released an evaluation report that referred the exploration program to the Executive Council for screening.

Future oil and gas development in Yukon is inherently tied to the performance of oil and gas prices. Looking at the performance of the past 10 years, natural gas prices are shown to be quite variable, going as high as US$8.86 MMBTU in 2008 and falling as low as US$2.63 MMBTU in 2015.[19] At US$2.63 MMBTU, the price was down over 40 per cent from US$4.39 MMBTU in 2014. Many forecasters are calling for prices to decline in 2016, before posting growth in 2017.

Like natural gas, oil has seen its price decline substantially in recent history. After averaging over US$90 per barrel in every year from 2011 to 2014, oil prices declined dramatically in 2015,

averaging US$48.69 per barrel, down 48 per cent from 2014 and the lowest annual average since US$41.44 per barrel in 2004.[20] Increased supply and weaker demand have contributed to lower oil prices, and these factors are expected to continue to weigh on oil prices in the near term as oil is expected to average about US$40 per barrel in 2016. Prices are expected to recover somewhat in 2017, averaging almost US$50 per barrel, well below levels seen in the last ten years.

Any development of Yukon's hydrocarbon resources will be shaped in part by decisions related to the production process of hydraulic fracturing. In an effort to engage with Yukoners and generate discussion on what has become a high profile, public topic, the Select Committee Regarding the Risks and Benefits of Hydraulic Fracturing was formed.

The final report of the Select Committee was released on January 19, 2015 and included 21 recommendations. The recommendations focus on the need for continued public dialogue, continued First Nation engagement, detailed assessment of the economic, human health and social impacts, more baseline data and scientific research around water, greenhouse gases, air emissions, wildlife and induced seismicity and assurance that regulatory processes will protect the safety of people and the environment.

The Government of Yukon has stated that it agrees with all 21 recommendations, and has developed an Action Plan on Oil and Gas Development to address many of these areas. Included in this Action Plan is a plan for dialogue on how to responsibly develop oil and gas resources with the public and First Nations; the need to conduct a study of the economics associated with unconventional oil and gas development; requirement for baseline water monitoring work; the need for expanded seismic baseline data; and a discussion of exploring partnerships with affected First Nations and other potential partners.[21]

Outlook for Oil & Gas

- Future development will depend on a number of factors including the performance of oil and natural gas prices and decisions made related to the use of hydraulic fracturing in the territory.
- There is interest in using LNG for power generation in proposed mines in Yukon.
- Production of local resources could offset future hydrocarbon imports.

TOURISM

Tourism activities have long been an important contributor to Yukon's economy, often serving as a stabilizing force for Yukon's economy during times when the mining sector has struggled. Tourism related activities add to the diversity of the local economy, help promote the territory, and support employment across a wide variety of local goods and services providers. Retailers, grocery stores, accommodations providers, restaurants, as well as providers of sports and recreational activities and providers of arts and culture all benefit annually from visitors to the territory.

Tourism activities over-lap a number of industries, therefore determining the economic contribution of tourism is not straight-forward. Accommodations & Food Services, Retail Trade and Transportation & Warehousing are three industry classifications where tourism related

activities are reflected strongly. One of the more recent attempts to capture the economic contribution of tourism is noted in the 2015 *Yukon Business Survey* where Yukon businesses are cited as attributing $226.9 million of their gross revenue in 2014 to tourism and based on these revenues the total GDP attributable to tourism was estimated at about $95.9 million, representing almost four per cent of Yukon's total GDP in 2014.[22]

Based on reporting from the Canada Border Services Agency (CBSA), the Department of Tourism & Culture notes a decline in total border crossings for 2015, with 327,778 people crossing international borders in Yukon, a decrease of 13,929 or 4.1 per cent from 2014. Excluding Yukon residents, who are not traditionally considered tourists, total border crossings were down 7,151 people, or 2.4 per cent, over 2014. Since posting a 20-year low in 2009, crossings have been well over 300,000 annually, averaging over 330,000 for the period 2010 to 2014. While an imperfect indicator of tourism performance, international border crossings are often used as a performance measure.

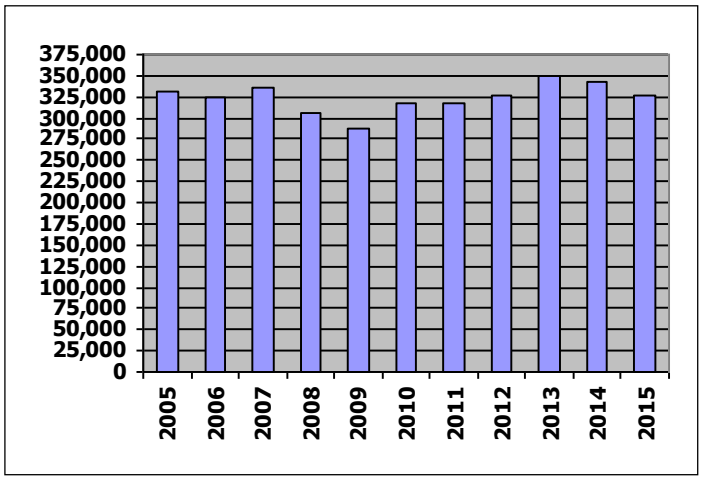


Figure 11 – Border Crossings
(Includes International Air Travel)
Source: Canada Border Services Agency

Anecdotally, Yukon's tourism industry has indicated that 2015 was a good year for tourism and a number of tourism indicators support their perspective. Air arrivals at Erik Neilson Whitehorse International Airport were up 1.7 per cent compared to 2014 with over 156,000 passengers arriving at the airport.[23] Visitation to Yukon Visitor Information Centres was also up 2.4 per cent recording 252,349 visits. Attendance at the Beringia Interpretive Centre was up 6.0 per cent and visitation to Parks Canada's Kluane National Park and Reserve and National Historic Sites were up 8.2 and 5.9 per cent, respectively, compared to the same period last year.[24] The number of non-residents camping at Yukon Government campgrounds was up 13.6 per cent, and the number of non-resident person nights spent at government campgrounds were up 16.6 per cent over 2014.[25]

Further, border crossings provided by U.S. Customs and Border Protection indicate that the number of people entering Alaska from Yukon were up 1.1 per cent to 404,751 people compared to the same period in 2014.[26]

Looking ahead, a weakened Canadian dollar, lower fuel prices, improving consumer confidence, and gains in domestic airline seat capacity are prominent among the factors that will likely impact tourism activities in the near-term.

After a prolonged period where the Canadian dollar performed well against the US dollar, often trading above par, the dollar saw a significant devaluation in 2015 and this has continued into 2016. The Canadian dollar traded at over US$0.90 for the majority of 2014 but began trending downward in the fall of the year. By the end of 2015, the dollar was trading in the low 70s, and in January 2016 dipped below US$0.70 for the first time since 2003. The persistence of a

weaker Canadian dollar may bode well for local tourism operators as visitation becomes more affordable for U.S. and some overseas visitors and may also result in Canadians becoming more inclined to vacation in their own country.

Lower oil prices have translated into lower gasoline prices. Lower fuel prices decrease the cost of travel via personal motor vehicle, and also possibly the costs of travel via motorcoach and airplane, if a portion of the fuel savings are passed along to the customer. Oil prices have fallen dramatically, down over 70 per cent in the last year and a half. Lower oil prices have contributed to lower fuel prices, with the price of regular unleaded gasoline in Whitehorse near $1.00 per litre at the time of writing.

As noted, anecdotal information for 2015 indicates that it was a positive year for the local tourism community. Expectations are that 2016 and 2017 will continue to grow upon the recent positive performance.

Outlook for Tourism

- Expectations are that the near-term will build on what many local operators noted as a good year in 2015.

CONSTRUCTION

Following a 65 per cent increase to $130.5 million in 2014, the value of building permits in 2015 are reported as falling to $117.7 million.

The value of non-residential permits declined in 2015, falling 2.6 per cent to $81.6 million. While down, non-residential permits continued to account for the majority of building permit value in 2015, representing 69 per cent of the annual total. Since the start of 2010, non-residential building permit value accounted for 59 per cent of the total building permit value of over $730 million.

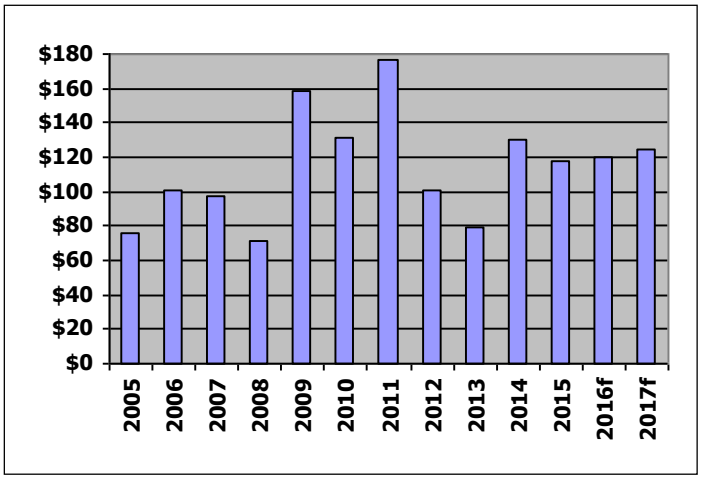


Figure 12 – Value of Yukon Building Permits ($ millions)
Source: Department of Economic Development; Yukon Bureau of Statistics

Contributing to the decline in non-residential permits in 2015 was a significant decline in the value of industrial permits which fell from $5.8 million to $769,000. Commercial permit value also fell in 2015, totalling $27.0 million, down about 15 per cent from $31.6 million in 2014. Countering a portion of the decline in non-residential permit value was an increase in government/institutional permit value, up 16 per cent to $53.9 million.

The value of residential permits showed a more significant decline in 2015, falling 22.5 per cent to $36.1 million. After totalling over $71 million in 2011 and almost $66 million in 2012, residential permit value has averaged about $39 million over the last three years. For the period 2010 to 2015, residential building permits accounted for 41 per cent of total building permit value, totalling just over $300 million.

Weaker residential activity in 2015 is also supported by the most recent Northern Housing Report[27] from the Canada Mortgage & Housing Corporation (CMHC), which forecasts a near 13 per cent decline in the number of housing starts, falling from 212 in 2014 to 185 in 2015. The annual decline in 2015 is noted as being similar for both single-detached starts, down 12.8 per cent to 95, and multi-family starts, down 12.6 per cent to 90. At 185, total starts in 2015 are well below the high of 332 in 2011, and the average of the previous five years of over 240 starts.

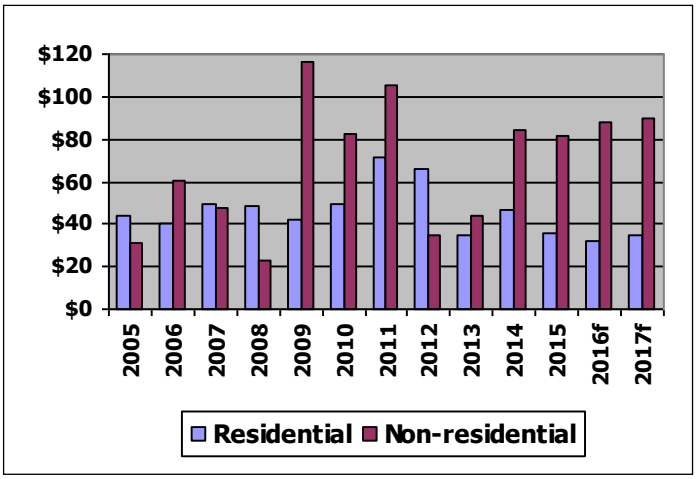


Figure 13 – Value of Yukon Building Permits – Residential vs. Non-residential ($ millions)
Source: Department of Economic Development; Yukon Bureau of Statistics

Estimates noted in 2016-17 budget documents have capital spending in 2015-16 at nearly $313 million, representing a record level of spending. Key areas of spending in 2015-16 include:

- There were a number of notable capital projects associated with health and social services, including the contruction of a 150-bed continuing care facility in Whitehorse ($26.0 million)[28], work related to the new Magnetic Resonance Imaging (MRI) scanner and expansion of the emergency department at the Whitehorse General Hospital ($22.3 million), construction of a new drug and alcohol detox centre to replace the Sarah Steele building ($16.4 million), the replacement of the Whitehorse Salvation Army building ($9.1 million), replacement of the McDonald Lodge continuing care facility in Dawson City ($7.8 million) and purchase and conversion of the Oblate Centre on 6th Avenue in Whitehorse to a small continuing care facility ($1.9 million).
- Notable projects related to community operations and infrastructure, included work related to planning of phase 3-5 of the Whistle Bend sub-division ($7.7 million), renovation of the Government of Yukon's main administration building ($5.4 million), replacement of the Carcross fire hall ($3.7 million), replacement of the Faro RCMP detachment ($3.5 million), construction of a recreation centre in Dawson City ($1.4 million) and water and sewer upgrades in various communities including Mayo ($6.6 million), Watson Lake ($4.8 million), Teslin ($2.1 million) and Watson Lake ($2.0 million), Mendenhall Subdivision ($1.8 million), Dawson City ($1.7 million), and Carmacks ($1.1 million).
- Spending on several projects related to transportation were noted for 2015/16, including $8.1 million for Campbell Highway reconstruction, $9.8 million for Shakwak permafrost remediation and crushing, $4.6 million for Atlin road improvements, $2.9 million for

work on the Dempster Highway, $2.1 million allocated to the Watson Lake Aerodrome, $1.5 million for work on the Partridge Creek Bridge and $1.3 million for the Whitehorse Corridor redevelopment.

- Education related construction activities are associated primarily with replacement of the F.H. Collins School in Whitehorse including $9.4 million for construction work and to upgrade the Technical Education Wing. Spending in 2015/16 also included $2.4 million for the Yukon College's Centre for Northern Innovation in Mining and $2.5 million for renovations of the Del Van Gorder School in Faro.
- Other notable projects identified in 2015-16 Government of Yukon spending include construction of a seniors housing project in Whitehorse ($9.5 million), the Keno-Stewart transmission line ($4.3 million), $2.0 million related to development of hydro infrastructure, and $1.8 million for development of rural residential land in Mount Lorne.

While falling below the record capital spending noted for 2015-16, the 2016-17 territorial budget delivered on April 7, 2016 includes a total capital spending figure of $306.6 million. Key areas of spending identified for 2016-17 include:

- Notable projects associated with health and social services, included continued work on a 150-bed continuing care facility in Whitehorse ($66.9 million), $21.9 million for the ongoing Whitehorse emergency department expansion and MRI at the Whitehorse General Hospital, a further $8.3 million for the new Salavation Army building being constructed in Whitehorse, an additional $7.3 million for replacement of the Sarah Steele alcohol and drug detox centre, and $1.7 million for the 6th Avenue continuing care facility in Whitehorse.
- Notable capital projects associated with supporting and improving community services include $21.7 million under the New Building Canada Fund including spending on a new wastewater treatment plant in Burwash Landing and upgrades to the Mayo water reservoir, $15.0 million associated with planning of phases 3-7 of the Whistle Bend sub-division, $4.4 million for upgrades to the Government of Yukon's main administration building, $3.0 million for a new firehall in Carcross, $2.2 million for a wastewater treatment facility in Ross River and $2.0 million for the sewage system in Carmacks.
- Among the notable projects related to transportation are the $12.0 million identified for spending on rehabiliating sections of the road covered under the Alaska Highway-Shakwak Agreement, $11.4 million for reconstruction and rehabilitation of the Robert Campbell Highway, $3.1 million for Dempster Highway erosion and rehabilitation, $3.9 million for work on the Erik Nielsen Whitehorse International Airport, $2.8 million for Community Airport improvements, and $2.5 million for Whitehorse Corridor passing and turning lanes on the Alaska Highway.
- The majority of education specific spending remains associated with the replacement of the F.H. Collins school in Whitehorse. The 2016-17 budget notes $3.0 million for construction of the F.H. Collins Technical Education Wing and $2.9 million for site development of the old F.H. Collins School.
- Other notable projects identified in the 2016-17 budget include $7.2 million from the CMHC for Investments in Affordable Housing, $5.6 million for the expansion of the Department of Tourism & Culture's Archives Vault Expansion, $4.0 million under the the Rural Land Development Program and $3.0 million for the construction of a 6-unit residential staff housing building in Ross River.

The City of Whitehorse's building consolidation project is another major initiative that will impact the local economy in the near-term. The City of Whitehorse's Capital Budget 2016-2019 notes a total capital cost of over $56 million for this project with almost $50 million of that slated to be spent in 2017.

Because of questions regarding timing of permits, and what future construction activities may require permits, forecasting the value of building permits can be difficult. As well, the performance of mineral prices and the subsequent impact on the local mining sector continue to be key determinants of the nature and level of construction activity in Yukon. Given the current uncertainty in the global mining sector and what it could mean for local mining activities, the risk to the building permit outlook is elevated. In terms of the value of building permits, modest gains in the value of residential and non-residential building permits are anticipated for 2016 and 2017 with growth focused primarily in non-residential permits.

Outlook for Construction

- The value of building permits is expected to grow modestly in the next two years.
  - Construction activities in the realm of health and social services are expected to be a key driver of the value of institutional building permits and overall building permits in the near-term.

RETAIL TRADE

Data from Statistics Canada indicates that Yukon reported a record level of retail sales in 2015, with the value of $692.2 million[29] representing annual growth of 4.7 per cent from $660.9 million. While growth in 2015 was anticipated, the impressive annual growth was unexpected given recent weaker economic performance.

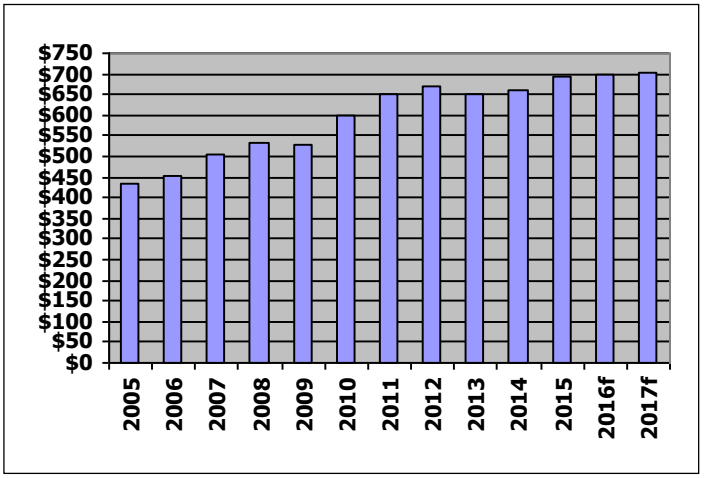


Figure 14 – Value of Retail Sales ($ millions)
Source: Department of Economic Development; Yukon Bureau of Statistics

Among categories of retail sales that are not suppressed for Yukon, sales from Food and Beverage Stores represented the largest component in 2015 accounting for over 29 per cent of total sales, increased by 2.7 per cent to $203.4 million. The value of sales related to Gasoline stations, the second largest component of retail sales, were reported as increasing slightly (up 0.3 per cent) to $107.8 million in 2015 as lower gasoline prices dampened sales. Sales from Health and Personal Care Stores were also reported as being up in 2015, with the estimated value of $37.5 million up 17.1 per cent from $32.0 million in 2014.

Sales from Furniture and Home Furnishings Stores were noted as being down in 2015, declining 4.6 per cent to $12.9 million.

Due to issues around confidentiality, retail sales data for other retail classifications are suppressed.[30] Total sales from these suppressed classifications in 2015 totalled $330.7 million, well above the $310 million recorded in 2014.

Growth in the short-term is expected to be modest with the current forecast calling for growth of 0.8 per cent in 2016 and 1.1 per cent in 2017.

Outlook for Retail Trade

- Statistics Canada reports the value of retail sales in 2015 at over $692 million, up 4.7 per cent from $660.9 million in 2014.
- Retail sales are forecast to grow 0.8 per cent in 2016 and a further 1.1 per cent in 2017.
- A weaker economy and continued weakness in the mining sector increases the uncertainty for the near-term performance of retail sales.

KEY ECONOMIC INDICATORS

Indicator	*2014*	*2015*	*2016f*	*2017f*
Population, Prices, Rates				
Population (June)	37,251	37,343	37,600	37,750
Population Growth Rate	1.7%	0.2%	0.7%	0.3%
CPI Growth Rate^	1.3%	-0.2%	2.0%	2.0%
Overnight Rate	1.00%	0.63%	0.50%	0.69%
Canada/U.S. Exchange Rate	$0.906	$0.783	$0.757	$0.777
Employment ƒ				
Labour Force	20,700	20,700	20,900	21,000
Employment	19,800	19,400	19,500	19,650
Unemployed	900	1,300	1,400	1,350
Unemployment Rate	4.3%	6.3%	6.6%	6.3%
Economic Output				
Real GDP By Industry (billions of chained 2007 $)	$2.264 (r)	$2.177 (p)	$2.238	$2.111
Real GDP Growth Rate	-0.8%	-3.8%	2.8%	-5.7%
Commodity Prices~				
Gold ($US/oz)	$1,266	$1,160	$1,170	$1,150
Silver ($US/oz)	$19.08	$15.70	$14.75	$15.00
Zinc ($US/lb)	$0.98	$0.88	$0.80	$0.95
Copper ($US/lb)	$3.11	$2.50	$2.10	$2.20
Oil - WTI ($US/bbl)	$93.26	$48.69	$37.00	$47.00
Natural Gas – Henry Hub ($US/MMBTU)	$4.39	$2.63	$2.25	$3.20
Mining				
Value of Mineral Production	$408.0 million (r)	$246.9 million (p)	$375 million	--
Exploration Expenditures	$107.1 million	$73.3 million	$56.4 million	--
Development Expenditures	$50 million	$28 million	$27 million	--
Construction				
Permitted Building Construction	$130.5 million	$117.7 million	$120 million	$125 million
Trade				
Value of Retail Sales	$660.9 million	$692.2 million	$698 million	$705 million
Tourism				
Non-resident Border Crossings+	341,707	327,778	--	--

f = forecast, e = estimate, p = preliminary, r = revised, -- = not available
^ CPI increase for Whitehorse only
ƒ annual averages – Labour force and employment rounded to nearest 100. Totals may not add due to rounding.
~ annual averages
+ as reported by the Department of Tourism & Culture

DATA SOURCES FOR KEY ECONOMIC INDICATORS TABLE

Indicator	*Source*
Population	Yukon Bureau of Statistics, Yukon Population Estimates, Yukon Department of Economic Development
Inflation (Consumer Price Index)	Statistics Canada, Consumer Price Index, Yukon Department of Economic Development
Overnight Rate	BMO Capital Markets
Canada/U.S. Exchange Rate	BMO Capital Markets
Labour Force Indicators	Statistics Canada, Yukon Labour Force Survey, Yukon Department of Economic Development
Economic Output (Real GDP)	Statistics Canada, Provincial Economic Accounts, Yukon Department of Economic Development
Commodity Prices	BMO Capital Markets
Value of Mineral Production	Natural Resources Canada Minerals and Mining Statistics Division, Yukon Department of Economic Development
Mineral Exploration Expenditures	Natural Resources Canada; Minerals and Mining Statistics Division
Mine Development Expenditures	Yukon Department of Energy, Mines & Resources, Yukon Department of Economic Development
Tourism Visitation	Yukon Department of Tourism & Culture, Yukon Department of Economic Development
Permitted Building Construction	Yukon Bureau of Statistics, Yukon Department of Economic Development
Retail Trade	Statistics Canada, Yukon Department of Economic Development

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[7] Bank of Canada maintains overnight rate target at ½ per cent. Bank of Canada. http://www.bankofcanada.ca/2016/04/fad-press-release-2016-04-13/
[8] Commodity Forecasts (April 20, 2016). BMO Capital Markets. http://www.bmonesbittburns.com/economics/goods/current/
[9] MMBTU refers to a million British thermal unit (Btu)
[10] The "Public Sector" is an aggregation of the industry classifications of Public Administration, Educational Services Health Care & Social Assistance and.
[11] Includes City of Whitehorse and surrounding area as well as the community of Marsh Lake.
[12] Consumer Price Index data is only available in Yukon for Whitehorse.
[13] Exploration and deposit appraisal expenditures include on-mine-site and off-mine-site activities; field work, overhead costs, engineering, economic and pre- or production feasibility studies, environment, and land access costs. Expenditures also include only the search for and appraisal of deposits and do not include work for extensions for known reserves.
[14] The exploration work phase is defined as the search for, discovery, and first delimitation of a previously unknown mineral deposit or the re-evaluation of a sub-marginal or neglected mineral deposit in order to enhance its potential economic interest based on delimited tonnage, grade, and other characteristics. The phase is completed when a deposit has sufficient indicated mineral resources accompanied by a positive scoping study (preliminary economic assessment that justifies additional, more detailed, and costly deposit appraisal work.
[15] The deposit appraisal work phase is defined as the steps undertaken to bring a delimited deposit, by definition drilling, comprehensive tests, and planning, to the stage of detailed knowledge required for a complete feasibility study that will fully justify and support a production decision and the large investment required.
[16] Capstone Mining 2016 Operating and Capital Guidance. http://capstonemining.com/news/news-details/2016/Capstone-Mining-2016-Operating-and-Capital-Guidance/default.aspx
[17] Northern Cross (Yukon) Limited Open House Presentations (June 16-18, 2014). http://www.northerncrossyukon.ca/upload/news_item/11/02/community-open-house-presentations-june-2014.pdf
[18] Eagle Plains Multi-well Exploration Program. Project Proposal Summary YESAB Registry. http://www.yesabregistry.ca/wfm/lamps/yesab/lowspeed/projectsummary.jsp;time=1434126836032
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[24] Parks Canada, Yukon Field Unit.
[25] Department of Environment, Parks Unit.

[26] Bureau of Transportation Statistics Border Crossing/Entry; January to December 2015. United States Department of Transportation. http://transborder.bts.gov/programs/international/transborder/TBDR_BC/TBDR_BC_Index.html
[27] Northern Housing Report 2015. CMHC. http://www.cmhc-schl.gc.ca/odpub/esub/65446/65446_2015_A01.pdf?fr=1456331518178
[28] Values represent estimated spending for the fiscal year in question and do not necessarily reflect the entirety of capital spending for each project. Spending estimates are rounded down to the nearest one decimal.
[29] Retail sales data is unadjusted for inflation.
[30] Data suppressed but included in the total: Motor Vehicle and Parts Dealers; Electronics & Appliance Stores; Building Material & Garden Equipment; Clothing & Clothing Accessories Stores Sporting Goods, Hobby, Book & Music Stores; General Merchandise Stores; and Miscellaneous Store Retailers, and Supplies Dealers.

FBC 2023 ANNUAL REVIEW OF RATES
EXHIBIT B-2

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August 5, 2022

British Columbia Utilities Commission
Suite 410, 900 Howe Street
Vancouver, BC
V6Z 2N3

Attention: Ms. Sara Hardgrave, Acting Commission Secretary

Dear Ms. Hardgrave:

Re: FortisBC Inc. (FBC)

Multi-Year Rate Plan for 2020 through 2024 approved by British Columbia Utilities Commission (BCUC) Order G-166-20 (MRP Plan)

Annual Review for 2023 Rates

In accordance with the MRP Plan and BCUC Order G-193-22 setting out the Regulatory Timetable for FBC's Annual Review, FBC hereby attaches its Annual Review for 2023 Rates Application materials.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC INC.

Original signed:

Diane Roy

Attachments

cc (email only): Registered Interveners to the FBC Annual Review for 2022 Rates

FORTIS BC™

FORTISBC INC.

Annual Review for 2023 Rates

August 5, 2022

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1. APPROVALS SOUGHT, OVERVIEW OF THE APPLICATION AND PROPOSED PROCESS

1.1 *INTRODUCTION*

FortisBC Inc. (FBC or the Company) files this Application in compliance with British Columbia Utilities Commission (BCUC) Order G-166-20, which approved a Multi-Year Rate Plan (MRP or the Plan) for FBC for the years 2020 to 2024. In accordance with the MRP, an annual review process is required to set rates for each year of the MRP.

The MRP provides stable levels of O&M funding and includes service quality indicators (SQIs) to monitor the maintenance of service quality. The approved Earnings Sharing Mechanism (ESM), set out in Section 10, aligns the incentive properties of the Plan between customers and the Company.

As explained in Section 10 of the Application, FBC proposes to distribute $0.911 million pre-tax ($0.665 million after-tax) in earnings sharing to customers in 2023.

The proposed rates for 2023 flowing from the approved formulas and forecasts set out in the Application, including returning the actual 2021 earnings sharing to customers, result in a 3.99 percent rate increase from 2022 rates. The increase is primarily due to an increase in power purchase expense (PPE) as well as rate base growth.

In the subsections below, FBC sets out the approvals it is seeking and provides an overview of the requirements for the annual review process. This is followed by a discussion of FBC's 2021 formula O&M savings and the productivity initiatives that FBC is developing. Finally, FBC provides a summary of its proposed revenue requirements and rate changes for 2023 and a summary of the SQI results. These matters are addressed in more detail in subsequent sections of the Application.

1.2 *APPROVALS SOUGHT*

With this Application, FBC requests BCUC approval for the following pursuant to sections 59 to 61 and 89 of the *Utilities Commission Act* (UCA):

1. Approval to recover the 2023 revenue requirement and resultant rate change on an interim basis, effective January 1, 2023, as filed in the Application and subject to any adjustments identified by FBC during the regulatory process and from any directives or determinations made by the BCUC in its decision on the Application. Rates will remain interim pending the outcomes of the BCUC's current generic cost of capital (GCOC) proceeding and FBC's 2023-2027 Demand Side Management (DSM) Plan proceeding.
2. The level of forecast growth, sustainment and other capital to be incorporated in rates for the years 2023 and 2024, as set out in Section 7.2.1.

3. The following deferral account approvals, as described in Section 7.6:

   - Creation of a rate base deferral account for the 2023 Joint Pole Use Audit, with the balance in the deferral account to be amortized over five years commencing January 1, 2023; and
   - Approval of a three-year amortization period for the existing COVID-19 Customer Recovery Fund Deferral Account, commencing January 1, 2023.

4. Approval to cease reporting on the COVID-19 Customer Recovery Fund Deferral Account, as described in Section 7.6.2.1.

FBC also seeks approval pursuant to section 99 of the UCA to vary the following Orders:

1. Directive 6 of Order G-42-21 in order to facilitate the return of the net incremental COVID-19 related cost reductions to customers through inclusion of the cost reductions in the Flow-through deferral account, as described in Section 12.2.1.

2. Directive 2 of Order G-83-14 to ensure that FBC continues to have approval from the BCUC to use US GAAP for regulatory accounting purposes, as described in Section 12.3.1.

A draft order is included in Appendix D.

1.3 *REQUIREMENTS FOR THE ANNUAL REVIEW*

On page 167 of the MRP Decision, the BCUC set out its expectations for the Annual Review component of the MRP. For reference, the table below sets out each requirement and FBC's response or where it is addressed in the Application.

Table 1-1: Annual Review Requirements

Item	Description	Response or Reference
1	Review of the current year projections and the upcoming year's forecast. For further clarity, these items are listed below:	See items 1(a) to 1(f) below
1(a)	Customer growth, volumes and revenues;	Section 3
1(b)	Year-end and average customers, and other cost driver information including inflation;	Section 2
1(c)	Expenses, determined by the indexing formula plus items forecast annually;	Section 6
1(d)	Capital expenditures (as provided for by the capital forecast), plus other items forecast annually;	Section 7
1(e)	Plant balances, deferral account balances and other rate base information and depreciation and amortization to be included in rates; and	Sections 7 and 12
1(f)	Projected earnings sharing for the current year and true-up to actual earnings sharing for the prior year.	Section 10

Item	Description	Response or Reference
2	Identification of any efficiency initiatives that the Utilities have undertaken, or intend to undertake, that require a payback period extending beyond the MRP period with recommendations to the BCUC with respect to the treatment of such initiatives.	FBC has not identified any efficiency initiatives with a payback beyond the end of the MRP period
3	Review of any exogenous events that the Company or stakeholders have identified that should be put forward to the BCUC for review.	Section 12.2
4	Review of the Utilities' performance with respect to SQIs. Bring forward recommendations to the BCUC where there have been a "sustained serious degradation" of service.	Section 13
5	Assess and make recommendations with respect to any SQIs that should be reviewed in future Annual Reviews.	FBC does not have any recommendations at this time
6	Reporting on the Innovation Fund status.	Not Applicable for FBC
7	Assess and make recommendations to the BCUC on potential issues or topics for future Annual Reviews.	FBC does not have any recommendations at this time

1.4 *FORMULA O&M SAVINGS AND PRODUCTIVITY INITIATIVES*

1.4.1 Overview of 2021 Formula O&M Savings

For 2021, FBC achieved formula O&M savings in addition to meeting the embedded productivity improvement factor in the O&M formula. Total formula O&M savings before earnings sharing were approximately $3.4 million.

Approximately $0.9 million in formula O&M savings were realized due to the net incremental impact of the COVID-19 pandemic, which will be returned to customers via the Flow-through deferral account. Please refer to Section 12.2.1 for further details. Lower spending in the Finance and Information Systems departments of approximately $0.6 million from vacancies, reduced consulting, and lower computer consulting services and expenses contributed to the savings. Additionally, approximately $2.2 million of O&M savings were due to the timing of expenditures, such as vacancies and consulting expenditures, and lower general and miscellaneous expenditures. These savings were partially offset by approximately $0.3 million of higher spending compared to the formula amount for incremental expenditures related to System Operations, Integrity and Security. Please refer to Section 6.2.1 for further details. While some of the savings are one-time in nature (e.g., delay in filling vacancies), some of the savings are expected to continue into the future, recognizing that cost pressures in the future may offset the savings.

FBC will continue to pursue productivity improvements to achieve savings beyond the productivity improvement factor as it seeks to manage its business needs and cost pressures resulting from its evolving and challenging operating environment.

1.4.2 Productivity Initiatives

As mentioned in FBC's Annual Review for 2022 Rates (2022 Annual Review), in 2021, FortisBC Energy Inc. (FEI) and FBC (together FortisBC) initiated a working group consisting of senior managers and directors from different parts of the organization that is responsible for reviewing and identifying areas for productivity initiatives. An area of focus for potential productivity opportunities is initiatives that offer financial and customer service benefits and leverage technology and innovation to achieve these benefits.

Following is a summary of productivity initiatives from different parts of the organization FortisBC reviewed this past year and/or is investigating.

1. **Field Operations Improvements:** This initiative was investigated through collecting feedback and analyzing efficiency gains within FBC's Outage Management System (OMS) and Mobile Workforce Management System (MWFM). Changes have been made to the software and processes that allow for improved information sharing and functionality when dispatching and performing jobs. This allows for less manual intervention and a more streamlined workflow. On a separate, but related initiative, enhancements are also underway to provide FBC's storm response restoration teams with an improved interface to access triage information. This will allow for a better prioritization of repairs, and a more efficient allocation of the available resources, resulting in faster restorations.

2. **Use of Unmanned Aerial Vehicles (UAVs - Drones):** FBC is investigating using UAVs to perform transmission line condition assessments. In 2021, FBC requested its contractor performing condition assessments to incorporate the use of drones for collecting data for certain suspected deficiencies. This use of drones was expected to reduce the need for follow-up bucket truck inspections to confirm deficiencies that cannot be fully assessed from the ground, and allow FBC to prepare work-packages for deficiencies identified during condition assessments in a more timely manner. Additionally, some of the drone-collected data has been used to help assess potential system upgrades and reconfigurations without requiring additional field verification of existing assets. For 2022, FBC is developing a request for pricing to assess the potential efficiencies associated with a condition assessment program relying exclusively on drone-collected data and the use of artificial intelligence and machine learning to help identify and categorize deficiencies related to FBC's transmission assets. Should a proponent be identified through this process, it is expected that this work will help validate the use of these techniques for performing condition assessment work and also help quantify the potential cost-savings associated with a drone-based approach for condition assessments.

3. **Technology Investments to Support Enhanced Communications:** FBC introduced enhancements during the COVID-19 pandemic to enable employees to productively work remotely. The implementation of the Microsoft Teams platform was expedited in 2021, allowing for use of video meetings for employee communications. In 2021, FBC also introduced the Microsoft Teams mobile app that provided seamless integration and access to Teams meetings, Teams sites, calendar, chat functionality and a seamless transition

from phone to computer or vice versa during meetings. It was and continues to be a platform to reduce travel requirements for staff, providing options to meet in person less often, which enables continued savings on fuel costs, hotels, meals, and wear and tear on vehicles. Hybrid meetings support large audience attendance using Teams meetings, with the added benefit of not requiring time away from the home office and the resulting lost productivity. Additional functionality will continue to be added to the Teams platform (i.e., whiteboard, enhancements to breakout rooms, Presenter modes and group control of presentation, etc.) as Microsoft continues to develop and release upgrades. The mobile application will also see improvements.

The Company's rapid implementation of communications software during the pandemic has contributed to creating a productive work environment for employees to complete their work with the benefit of not requiring time away from the home office and lost productivity. In total, FBC invested approximately $0.2 million over the two years 2020 and 2021. This investment has contributed to achieving employee-related expense savings (i.e., travel) during the pandemic and will also help to permanently sustain some of the related savings post pandemic.

4. **Data Analytics:** This is an initiative to centralize the Company's data sources coupled with a suite of analytic tools to analyze and use the data to inform decision-making. Data analytics is the process of extracting and analyzing data sets to identify or uncover patterns, correlations, trends, customer preferences and other information for the purpose of allowing an organization to make more informed business decisions. Better decisions will lead to improved business operations and customer service and increased productivity. The ability to easily access and analyze data can be inhibited by internal processes, decentralization of information and a lack of understanding of the data. With Data Analytics, departments will be provided a common cleansed data source and the tools to create advanced analytics quickly and easily. Resources will be provided to business areas to help identify reporting and analytic needs that will lead to efficiencies. Through a centralized approach, this will provide the skills along with the data and the tools to drive business capability to support analytic needs and also provide better visibility to costs or benefits of data analytics initiatives.

   The requirements and business case for the necessary information systems infrastructure were completed in 2021. FBC plans to implement systems that will allow centralized data access in 2022 and add new data sources in priority sequence over time. Data usage cases for this initiative are being prioritized first for those that enable cost savings.

5. **Streamlining and Automating Reporting Process:** This initiative is one of the earlier usage cases that FBC is considering for the Data Analytics initiative. The focus is on streamlining the reporting processes for financial and management reporting information (i.e., internal cost reporting, key performance indicators, etc.). Currently, the reporting processes work well with clearly defined requirements and processes but rely on manual effort. Source system (i.e., SAP) reports are not formatted for users and SAP reports are data extracts and are not set-up for data integration and manipulation. Instead, Excel is

used to integrate, transform and format reports. FBC is presently assessing the feasibility of implementing an automated solution that will reduce the effort required to generate reports, with expected productivity gains. This automation is expected to be achieved through the use of a data model to aggregate data sources and a reporting tool to allow for self-service.

FBC will be in a better position at next year's Annual Review to provide details of this initiative should it be undertaken, and to provide details of other specific data analytics initiatives undertaken and the benefits achieved.

6. **Robotics Process Automation (RPA):** This is an efficiency initiative using automation software to alleviate repetitive and simple manual tasks. With the rising volume of manual tasks performed for operational work, such as financial transactions or project closeout activities, departments within FBC are challenged. Both the Finance and Engineering departments have experienced an increase in manual activities over several years. Between steps performed multiple times daily, to weekly, monthly or annually, the common theme is a manual and repetitive task with limited decision points.

   In the first phase of RPA implementation, the Company is evaluating opportunities within the Finance and Engineering areas to apply RPA. There are a number of processes being evaluated for RPA with the focus on processes requiring supporting manual activities. The processes vary from creating journal entries, generating third party billing, populating reports, filing documents, and collecting information for budgeting purposes.

   FBC will be in a better position at next year's Annual Review to provide details of this initiative, including the results and benefits achieved.

7. **Paperless Billing Customer Campaigns:** This initiative focuses on working with customers to encourage the switch to paperless billing. In addition to the convenience for customers of receiving their bill electronically and the environmental considerations of less paper and physical transport of the bills, an increased percentage of customers making the switch to paperless billing results in ongoing printing and postage cost savings. At the start of 2021, FBC had approximately 69,000 customers choosing paperless billing as their preferred bill delivery method. Following the success of several internal programs that encouraged employees to highlight this option with customers and including an external social media campaign that resulted in donations to food banks in need, FBC achieved an increase of approximately 8,000 customers choosing this option in 2021. This increase equates to approximately $0.07 million in printing and postage cost savings in 2021 as compared to 2020.[1]

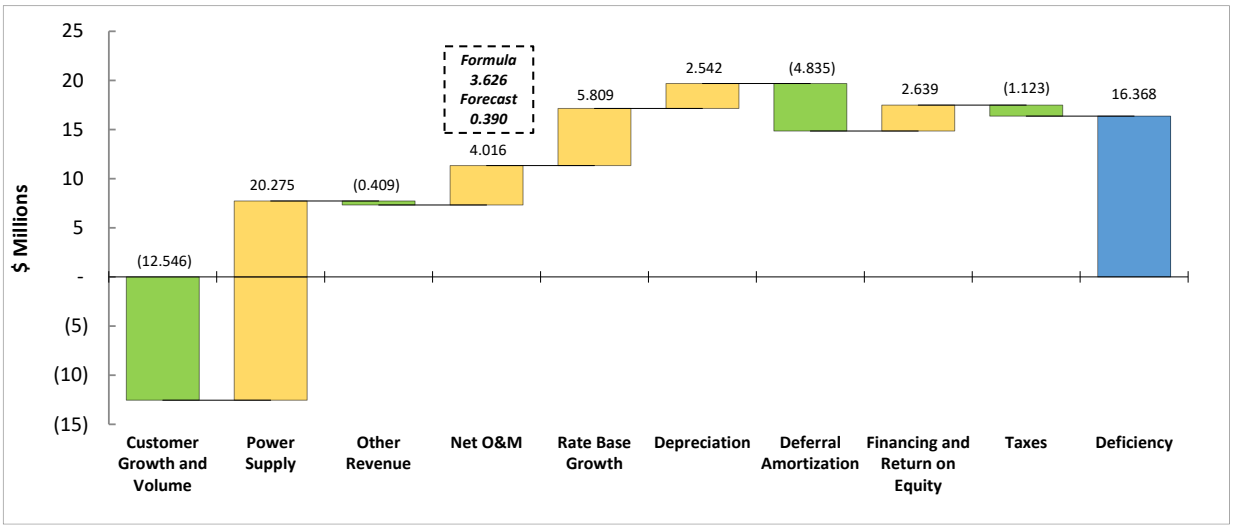
[1] Calculation is a high-level estimate based on the incremental monthly paperless billing growth at an average savings of approximately $1.24 per bill.

1.5 REVENUE REQUIREMENT AND RATE CHANGES FOR 2023

The revenue requirement components set out in the Application result in an effective rate increase of 3.99 percent for 2023 compared to 2022. The effective rate increase results from a revenue deficiency of $16.368 million.

The following chart summarizes the items that contribute to the 2023 revenue deficiency. The chart shows each item that increases the deficiency in yellow and each item that decreases the deficiency in green. The 2023 deficiency of $16.368 million is then the sum of all of the previous bars and is shown at the end of the chart in blue.

Figure 1-1: 2023 Revenue Deficiency ($ millions)



Each of the categories is discussed briefly below.

1.5.1 Customer Growth and Volume Forecast (Section 3)

For 2023, FBC forecasts a net load increase of 170 GWh compared to 2022 Approved, resulting in a decrease in FBC's 2023 revenue deficiency of $12.546 million. The increase in net load is primarily due to increased loads in the industrial classes, followed by smaller increases in the residential, commercial, wholesale, and irrigation classes. FBC's 2023 Forecast revenue at 2022 approved rates is $409.840 million.

1.5.2 Power Supply (Section 4)

FBC forecasts an increase in power supply of $20.275 million in 2023 compared to 2022 Approved. This increase is primarily due to the increase in load, and an increase in PPE under the BC Hydro Power Purchase Agreement (PPA) by approximately $27.240 million. This is offset by reduced market and contracted purchases by approximately $8.776 million.

1.5.3 Other Revenue (Section 5)

Other Revenue is forecast to increase by $0.409 million in 2023 compared to 2022 Approved. The main drivers of this increase are higher Late Payment Charges and the expected annual increases in rates for Apparatus and Facilities Rental, Contract Revenue and Transmission Access Revenue.

1.5.4 Operations and Maintenance (O&M) Expense (Section 6)

FBC establishes the majority of its O&M expense by formula during the MRP term. The O&M formula incorporates a net inflation factor of 4.017 percent, which is inclusive of a productivity improvement factor (X-Factor) of 0.5 percent, and uses a forecast of the change in average customers[2]. The 2023 Formula O&M net of capitalized overhead has increased by $3.626 million[3] when compared to the 2022 Formula O&M. Net O&M forecast outside of the formula is increasing by $0.390 million[4] over 2022 Approved, primarily due to an increase in pension and OPEB expense. Overall, the 2023 increase in total O&M expense net of capitalized overhead is $4.016 million (6.9 percent).

1.5.5 Rate Base Growth and Depreciation (Section 7)

The 2023 rate base is forecast to increase by approximately $92.524 million when compared to the 2022 Approved rate base, resulting in an increase to the 2023 revenue deficiency of $5.809 million. The increase in rate base is primarily the result of the mid-year impact of FBC's 2023 regular capital additions to plant, as well as the full-year impact of FBC's major capital project additions, including the Kelowna Bulk Transformer Additions (KBTA) project, the Corra Linn Dam Spillway Gates Replacement project, and the Playmor Substation Upgrade project, as described in Section 7.1.

The increase in rate base also results in an increase in 2023 depreciation expense by approximately $2.752 million compared to 2022 Approved, which is offset by approximately $0.210 million of CIAC from net additions, resulting in a net increase of $2.542 million in depreciation expense.

1.5.6 Amortization of Deferral Accounts (Section 7 and Section 12)

Amortization of deferral accounts in 2023 decreased by $4.835 million, primarily due to the credit amortization related to the 2020-2024 Flow-through non-rate base deferral account, partially offset by increases in the amortization expense of the DSM deferral account, the BCUC Initiated Inquiry Costs deferral account, and the COVID-19 Customer Recovery Fund deferral account. The credit amortization in the Flow-through deferral account in 2023 is $9.625 million, which is $5.698 million higher than the credit amortization in this account compared to 2022 Approved. As discussed in Section 12.4.2.1, the credit amortization in the Flow-through deferral account is

[2] Modified by 75 percent.
[3] Increase in gross formula O&M of $3.810 million (5.8 percent) compared to 2022 Approved.
[4] Increase in gross forecast O&M of $0.491 million (26.8 percent) compared to 2022 Approved.

primarily due to favourable revenue variances resulting from increased loads from industrial, commercial, wholesale, and residential classes.

1.5.7 Financing and Return on Equity (Section 8)

Financing and Return on Equity (ROE) increased the 2023 deficiency by $2.639 million through changes in financing rates, the ratio of long-term debt versus short-term debt, and changes in rate base.

For 2023, FBC is forecasting a short-term debt rate of 4.24 percent, which is an increase from the 1.51 percent short-term debt rate embedded in the 2022 Approved revenue requirement. Overall, FBC's deficiency is increased by $3.688 million from financing rate changes which is offset by $1.049 million from the ratio change between long-term and short-term debt.

In calculating its 2023 revenue deficiency, FBC has utilized its currently approved capital structure and ROE of 40 percent and 9.15 percent, respectively. As explained in Section 8.1, FBC's ROE is set at a premium of 40 basis points over the benchmark ROE, which is the ROE approved for FEI. FEI is currently participating in the BCUC-initiated GCOC proceeding and has filed evidence on its recommended capital structure and ROE as part of Stage 1 of the proceeding. In Order G-156-21 and accompanying Reasons for Decision, the BCUC found that the effective date to implement a new cost of capital will depend on the timing and progress of the GCOC proceeding. FBC is seeking approval of interim 2023 rates pending the outcome of Stage 1 of the GCOC proceeding as well as a decision on FBC's 2023-2027 DSM Expenditure Plan. When a decision is reached on these proceedings, FBC will update its rate calculations and apply for permanent 2023 rates.

1.5.8 Taxes (Section 9)

FBC's 2023 property taxes are forecast to increase by 2.1 percent or $0.371 million from 2022 Approved. The increase is primarily due to changes in tax rates and increases in assessed values, as well as an increase in grants in-lieu of taxes which are calculated based on a fixed percentage of FBC's revenue.

There has been no change in the income tax rate of 27 percent from 2022. Taxes are forecast to decrease in 2023 by $1.494 million due to higher deductible temporary differences associated with amortization of deferred charges and property, plant and equipment, and lower taxable temporary differences associated with pension and OPEB.

1.6 *SERVICE QUALITY INDICATORS (SECTION 13)*

FBC reports on its 2021 and June 2022 year-to-date SQI results in Section 13. In 2021, for the eight SQIs with benchmarks, six met or were better than the benchmark, with two better than the threshold. For the four SQIs that are informational only, performance in 2021 generally remains at a level consistent with prior years. In 2022 to date, performance for the metrics with benchmarks is trending towards meeting the benchmark or the threshold.

2. FORMULA DRIVERS

2.1 INTRODUCTION AND OVERVIEW

This section provides the calculation of the Inflation Factor (or I-Factor) and Growth Factor used for calculating the 2023 O&M amounts according to the MRP formula.

In the MRP Decision and Order G-166-20, the BCUC approved an I-Factor using the actual CPI-BC and BC-AWE indices from the previous year and a labour weighting based on the most recent completed year of actuals.[5]

The MRP Decision approved the use of a forecast of growth[6] to determine formula O&M and determined that a growth factor multiplier of 75 percent for formula O&M was appropriate.

The Inflation Factor and Growth Factor calculations utilize the above-described inputs and determinations. For 2023, FBC has used July 2020 through June 2022 inflation data for the 2023 revenue requirement calculations, using the Statistics Canada tables included in Appendix A1 of the Application.

2.2 INFLATION FACTOR CALCULATION SUMMARY

In the MRP Decision, the BCUC approved an I-Factor using the actual CPI-BC and BC-AWE indices from the previous year and the actual labour weighting based on the most recent completed year of actuals. FBC uses inflation data from July through June and Statistics Canada Table 18-10-0004-01 for CPI-BC and Table 14-10-0223-01 to determine AWE-BC. The supporting Statistics Canada tables are provided in Appendix A1. The latest available month of April 2022 for AWE-BC has been used as a placeholder, as results to June 2022 have not been released by Statistics Canada. Once results for these periods are available, this placeholder will be replaced with actuals and included in an Evidentiary Update or Compliance Filing.

As shown in Table 2-1 below, the I-Factor has been calculated utilizing actual CPI-BC and AWE-BC data. Applying the actual 2021 labour weighting of 60 percent, the calculation of the 2023 I-Factor is (4.940 percent x 40 percent) + (4.235 percent x 60 percent) = 4.517 percent.

[5] FBC's most recent year of completed actuals is 2021 so that ratio has been used for the 2023 I-Factor calculation.
[6] Forecast of average customers for Formula O&M, including a true-up to actual customers in the following years.

Table 2-1: I-Factor Calculation

Line No.	Date	*Table: 18-10-0004-01* BC CPI index	*Table: 14-10-0223-01* BC AWE $	12 Mth Average CPI index	12 Mth Average AWE $	CPI %	AWE %	Last Completed Year Non Labour %	Last Completed Year Labour %	I-Factor %	MRP Year
1	Jul-2020	132.6	1,093.72								
2	Aug-2020	132.4	1,089.35								
3	Sep-2020	132.5	1,093.75								
4	Oct-2020	132.9	1,095.32								
5	Nov-2020	133.3	1,102.95								
6	Dec-2020	132.8	1,110.36								
7	Jan-2021	133.6	1,113.22								
8	Feb-2021	134.1	1,114.21								
9	Mar-2021	134.9	1,107.66								
10	Apr-2021	135.2	1,112.04								
11	May-2021	135.1	1,118.59								
12	Jun-2021	135.8	1,115.40	133.8	1,105.55						
13	Jul-2021	136.7	1,140.52								
14	Aug-2021	137.0	1,142.40								
15	Sep-2021	137.2	1,139.64								
16	Oct-2021	137.9	1,136.85								
17	Nov-2021	138.1	1,132.25								
18	Dec-2021	138.0	1,134.84								
19	Jan-2022	139.4	1,157.19								
20	Feb-2022	140.4	1,153.88								
21	Mar-2022	143.0	1,161.22								
22	Apr-2022	144.2	1,176.54								
23	May-2022	146.1	1,176.54								
24	Jun-2022	146.5	1,176.54	140.4	1,152.37	4.940%	4.235%	40%	60%	4.517%	2023

2.3 GROWTH FACTOR CALCULATION SUMMARY

As noted above, the BCUC approved the use of a forecast of average customers with a 75 percent modifier to determine formula O&M.

The calculation of average customers used to determine 2023 Formula O&M is summarized in the table below. The growth factor is applied to the unit cost O&M (UCOM), which was calculated based on 2019 average customers of 139,916 (shown on line 21 under year 2020 or line 28 in Table 2-2 below). Starting with this 2019 average customer count, the calculation adds 75 percent of the cumulative average of actual/forecast customer growth during the MRP term from 2020 to 2023 (shown on line 26 in Table 2-2 below) to determine the average customers for rate setting (shown on line 29 of Table 2-2 below).

Table 2-2: Calculation of 2023 Average Customer (AC) Growth Factor

Line No.	Date	Actual 2020	Actual 2021	Projected 2022	Forecast 2023	Total for 2023 Rate Setting	Reference
1	Prior Year Ending Customer Count	141,027	143,714	145,830	148,861		Appendix A2 - Section 3.1 Customers
2							
3	Additions:						
4	January	292	257	226	256		
5	February	174	89	194	266		
6	March	8	123	122	264		
7	April	110	113	178	264		
8	May	173	319	537	255		
9	June	172	116	250	261		
10	July	522	308	255	265		
11	August	129	187	252	262		
12	September	83	136	254	264		
13	October	545	132	255	265		
14	November	234	217	252	262		
15	December	245	119	256	266		
16	Total Additions	2,687	2,116	3,031	3,150		Appendix A2 - Section 3.2 Customer Additions
17	12-month Weighted Average Additions	1,294	1,163	1,587	1,701		
18							
19	Current Year Ending Customer Count	143,714	145,830	148,861	152,011		Line 1 + Line 16; Appendix A2 - Section 3.1 Customers
20							
21	Actual/Projected Prior Year Average Customers	139,916	142,321	144,877	147,417		2020: G-42-21; Sch 3, Line 13; 2021 and 2022: Prior Year Ending, Line 22
22	Average Customers for the Year	142,321	144,877	147,417	150,562		Line 1 + Line 17
23	Change in Average Customers	2,405	2,556	2,540	3,145	**10,646**	Sum of Annual Change in Average Customers on Line 23
24							
25	Growth Factor Multiplier					**75%**	G-166-20
26	Change in Average Customers for Rate Setting Purposes					**7,985**	Line 25 x Line 23
27							
28	Average Customers Used to Determine the Starting UCOM					**139,916**	Line 21, Yr 2020
29	**Average Customer Forecast for Rate Setting**					**147,901**	Line 28 + Line 26
30							
31	2021 Approved Average Customers for Rate Setting		142,473				2021: G-42-21; Sch 3, Line 22
32	2021 Actual Average Customers for Rate Setting		143,637				Line 21(2020) + Sum of Line 23 (2020 & 2021) x 0.75
33	**2021 True Up**		**1,164**				Line 32 - Line 31

2.4 *INFLATION AND GROWTH CALCULATION SUMMARY*

A summary of the factors used to determine formula O&M for 2023 is provided in Table 2-3, including the I-Factor calculated in Section 2.2, the approved X-Factor of 0.5 percent, and the forecast of average customers incorporating the growth factor multiplier determined in Section 2.3.

Table 2-3: Summary of Formula Drivers

Line No.		2023	Reference
1	CPI	4.940%	Table 2-1, Line 24
2	AWE	4.235%	Table 2-1, Line 24
3			
4	Non Labour	40%	Table 2-1, Line 24
5	Labour	60%	Table 2-1, Line 24
6			
7	CPI/AWE Inflation	4.517%	(Line 1 x Line 4) + (Line 2 x Line 5)
8			
9	Productivity Factor	-0.500%	Order G-166-20
10			
11	Net Inflation Factor	4.017%	Line 7 + Line 9
12			
13	Average Customers for Formula O&M purposes	147,901	Table 2-2, Line 29

In summary, the Net Inflation Factor for 2023 is 4.017 percent and formula O&M for 2023 is determined using average customers of 147,901.

3. LOAD FORECAST AND REVENUE AT EXISTING RATES

3.1 *INTRODUCTION AND OVERVIEW*

This section describes FBC's forecast of gross system load. The gross system load is a combination of residential, commercial, wholesale, industrial, lighting and irrigation loads, system losses and company use. The forecast of gross system load includes the impacts of forecast load savings which include Demand Side Management (DSM) savings. These savings are further explained in Section 3.3 – Demand Side Management Savings.

FBC is forecasting an increase in consumption in the 2023 Forecast (2023F) compared to the 2022 Approved. The 2023F gross load is forecast to be approximately 3,775 GWh, which is a 184 GWh increase compared to the 2022 Approved gross load. The increase in 2023F is due to increased loads in the industrial, commercial, wholesale, residential and irrigation classes. Based on the 2022 Approved rates for each customer class, FBC's 2023 revenue forecast is $409.840 million.

FBC has provided further information supporting its load forecast in Appendix A of the Application.

3.2 *OVERVIEW OF FORECAST METHODS*

Consistent with the forecasting method followed by FBC in previous years, the load forecast relies on the following components:

- the residential and commercial customer count forecast;
- the residential use per customer (UPC) forecast;
- the commercial, lighting and irrigation load forecast; and
- the industrial and wholesale survey forecast.

The load forecast for residential customers is based on forecasts for the number of customers and UPC rates. Specifically, the UPC forecast is multiplied by the corresponding forecast of the number of annual average customers to derive the residential load forecast. The commercial load forecast is based on a regression against the Conference Board of Canada (CBOC) Gross Domestic Product (GDP) forecast, the lighting forecast uses the prior year's actual load, and the irrigation forecast uses a five-year historical average. Wholesale and industrial forecasts are primarily based on customer-specific survey results.

More detail on FBC's forecasting methods can be found in Appendix A of this filing.

The following sections set out the results of the load forecast. In the figures provided in the load forecast sections, the following three time periods are shown:

- Actual Years: Actual years are those for which actual data exists for the full calendar year. For this Annual Review the latest calendar year for which full actual data exists is the 2021 calendar year.
- Seed Year: The Seed Year is the year prior to the first forecast year. The Seed Year is forecast based on the latest years of actual data available,[7] and will be different than the original forecast for that year in the previous filing. For example, for this Application the Seed Year is 2022 (2022S) and the Seed Year forecast is based on the latest actual years, including 2021. As such, the 2022 Seed Year forecast in this Application will differ from the 2022 Forecast presented in the Annual Review for 2022 Rates, for which 2021 actual data was not available.
- Forecast Year: This is the year or years for which the forecast is being developed. This can be one year (in the case of the Annual Review) or a range of two or more years depending on the filing. In this Application, the forecast year is 2023 (2023F).
- Also included in the figures in this section is the prior year's forecast (shown as the green Approved lines in the figures below), as presented in the Annual Review for 2022 Rates.

FBC acquired the utility assets and customers of the City of Kelowna's electric utility effective March 31, 2013, resulting in an increase in direct customers and changes in the composition of customers and sales load by class, which are reflected in the data and figures in this section.

3.3 *DEMAND SIDE MANAGEMENT SAVINGS*

FBC forecasts the DSM savings that are incremental to the DSM savings that are already embedded in historical loads up to and including 2021.

The DSM savings forecast is deducted from the before-savings forecast for all customer classes. All forecast values in the sections below are shown after being reduced by DSM savings unless explicitly stated otherwise.

The forecast incremental DSM savings for 2023 are summarized in Table 3-1 below, and are the forecast savings incremental to the savings embedded in the historical loads. Historical DSM savings can be found in Appendix A2.

[7] FBC's load forecast is developed using only complete years of historical data. FBC requires the complete year of load data in order to validate it, including the review of and potential adjustments to unbilled energy. For this reason, partial year data is not used in forecasting.

Table 3-1: Forecast Incremental 2023 DSM Savings (GWh)

Line No.	Description	DSM 2023
1	Residential	(8.9)
2	Commercial	(22.6)
3	Wholesale	(7.7)
4	Industrial	(16.2)
5	Lighting	(0.3)
6	Irrigation	(0.2)
7	Net	(55.9)
8	Losses	(4.6)
9	Gross Load	(60.5)

3.4 *LOAD FORECAST*

FBC's total load consists of the weather normalized residential, commercial and wholesale load and the actual industrial, lighting and irrigation load. In aggregate, the absolute load forecast variance in 2021 was 0.2 percent. As shown in Figure 3-1 below, the total load, net of losses, is forecast to be 3,476 GWh in 2023F, which is 3 GWh more than 2022S and an increase of 170 GWh from 2022 Approved.

Figure 3-1: Total Net Load (GWh)

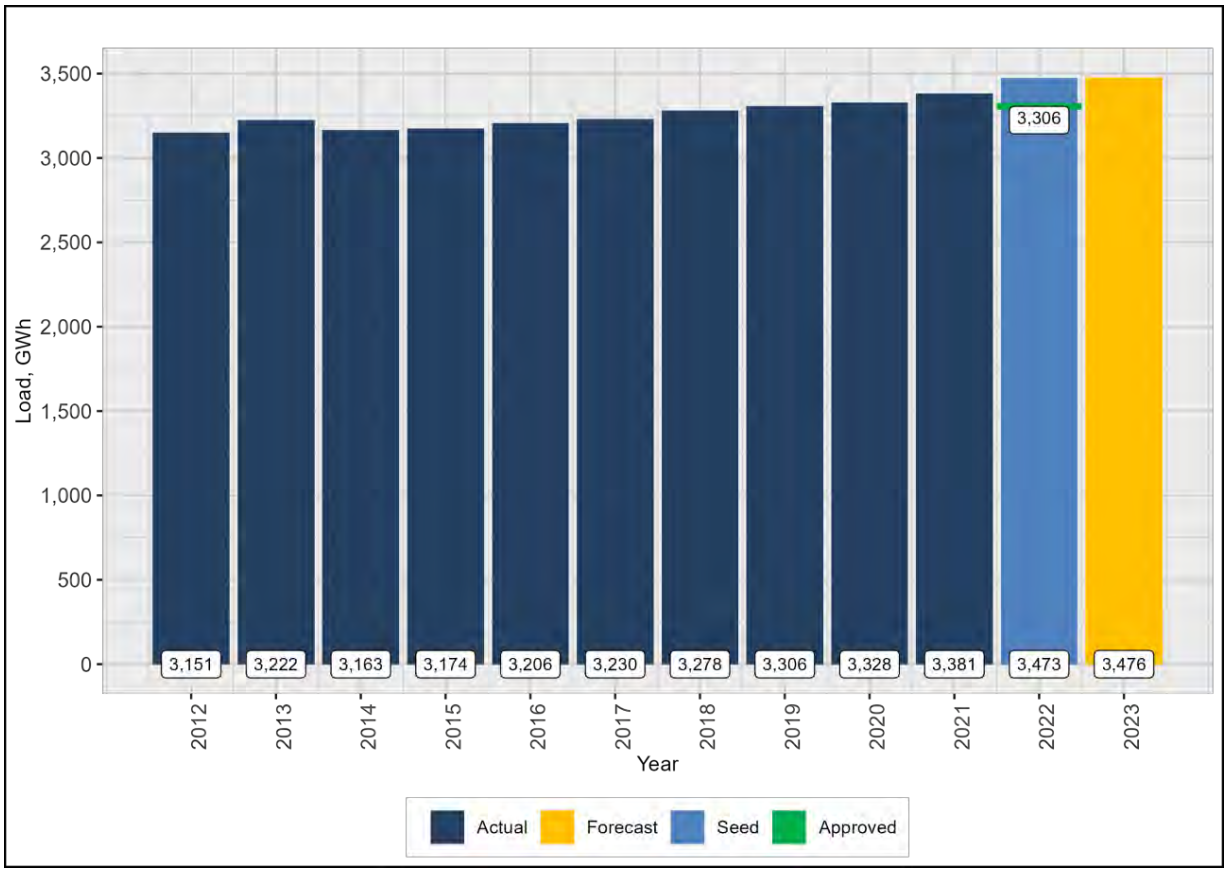


Table 3-2 below shows the normalized after-savings gross load by customer class as well as the system peak. For 2023F, the residential customer class is forecast to account for 34 percent of the normalized after-savings gross load.

Table 3-2: Normalized After-Savings Gross Load and System Peak

Line No.	Description	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022S	2023F
	Energy (GWh)												
1	Residential	1,229	1,353	1,296	1,298	1,296	1,320	1,313	1,266	1,347	1,330	1,304	1,301
2	Commercial	681	788	863	853	905	915	926	932	922	960	962	973
3	Wholesale	899	675	567	580	574	574	585	566	569	566	579	578
4	Industrial	291	352	381	380	373	363	403	495	441	472	579	575
5	Lighting	13.5	13.5	15.6	15.9	15.9	15.9	13.2	11.0	10.8	9.7	9.5	9.4
6	Irrigation	38.0	39.7	40.0	46.0	42.1	41.9	39.0	36.0	37.3	43.6	39.5	39.4
7	Net Load	3,151	3,222	3,163	3,174	3,206	3,230	3,278	3,306	3,328	3,381	3,473	3,476
8	Losses & Company Use	271	278	270	272	274	282	285	287	288	295	299	299
9	Gross Load	3,422	3,500	3,433	3,446	3,480	3,512	3,564	3,592	3,616	3,677	3,771	3,775
10													
11	System Peak (MW)												
12	Winter Peak	723	698	693	685	755	714	682	732	731	685	782	786
13	Summer Peak	589	600	620	611	593	605	631	639	666	653	678	684

The residential, commercial, wholesale, industrial, lighting, irrigation, loss load and the winter and summer peak demand forecasts are provided separately in the following subsections.

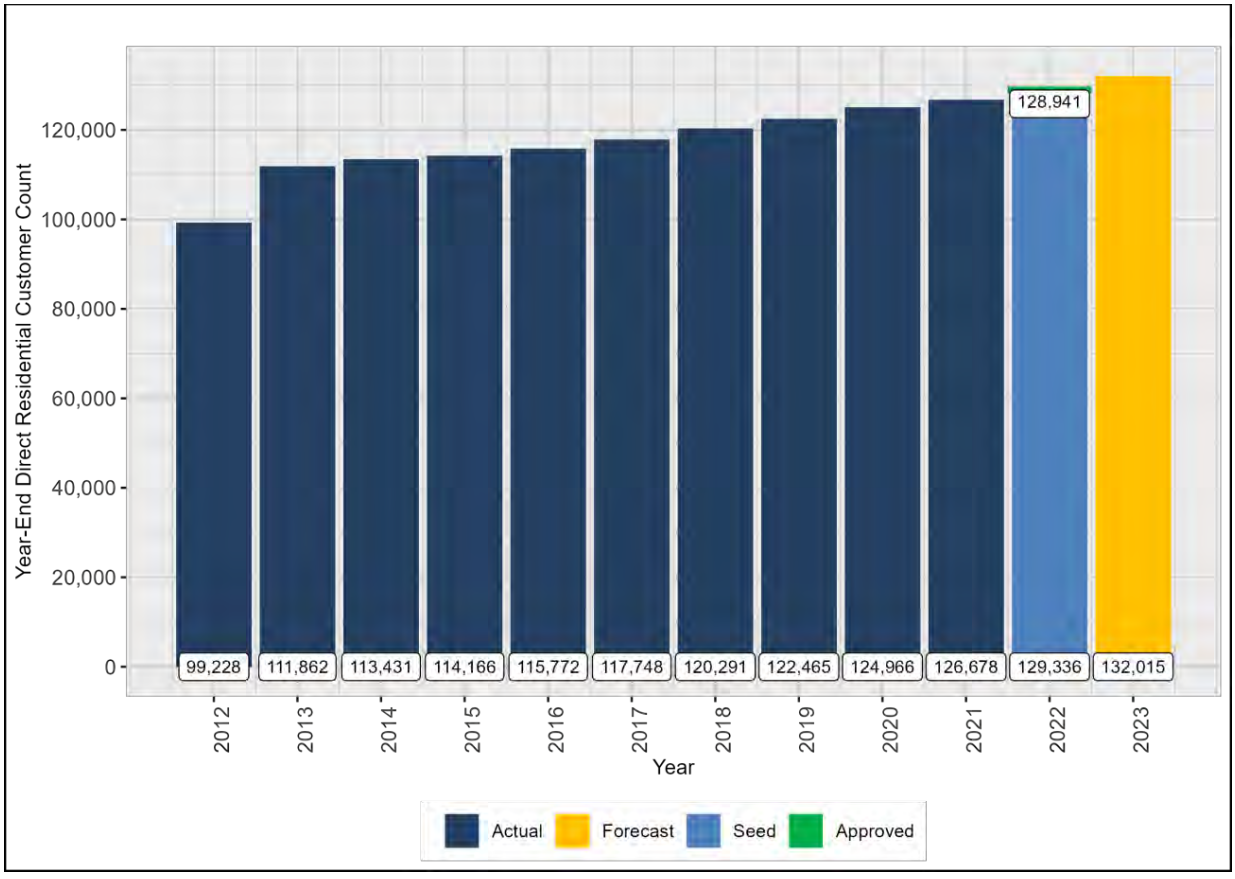
3.4.1 Residential

3.4.1.1 Residential Customers

Forecast residential customer counts are determined by a regression of the year-end customer accounts against population in the FBC direct service area. The population forecast for the FBC service area is provided by a BC Statistics report produced for FBC.

Figure 3-2 shows the year-end residential customer count for FBC.

Figure 3-2: Year-End Direct Residential Customer Count

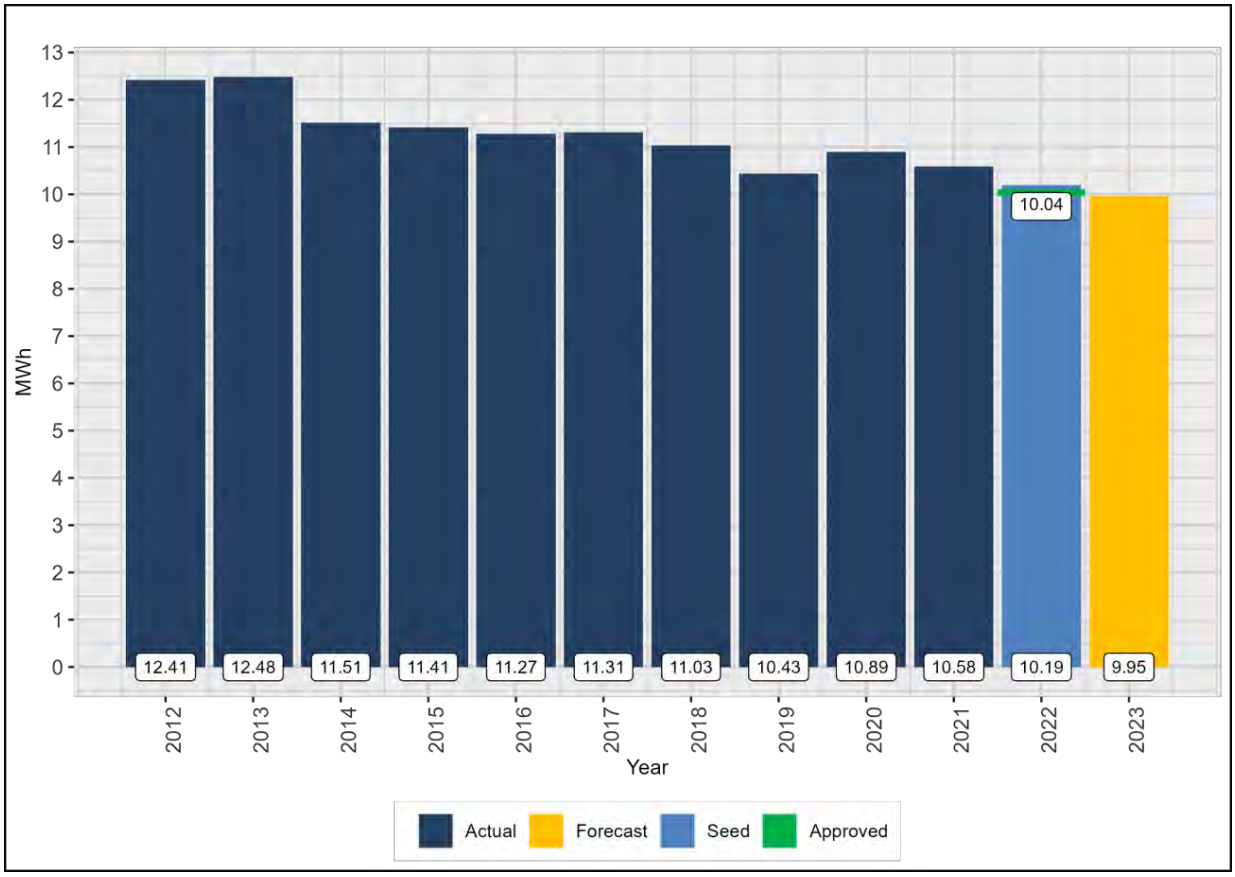


3.4.1.2 Residential UPC

Normalized historical UPCs are obtained by dividing the weather-normalized residential load by the average customer count in each year. The before-savings UPC is forecast by applying a 10-year trend to the normalized historical UPCs. The before-savings UPC forecast is then multiplied by the forecast average customer count to derive the before-savings load forecast. DSM savings, which are incremental to the savings embedded in the historical data to 2021, are then deducted from the before-savings load forecast to determine the after-savings load forecast. The after-savings UPC forecast is then calculated by dividing the after-savings load forecast by the average

customer count. As shown in Figure 3-3 below, the residential after-savings UPC is forecast to decrease by 0.24 MWh in 2023F from 2022S and decrease by 0.09 MWh from 2022 Approved.

Figure 3-3: Normalized After-Savings Residential UPC (MWh)

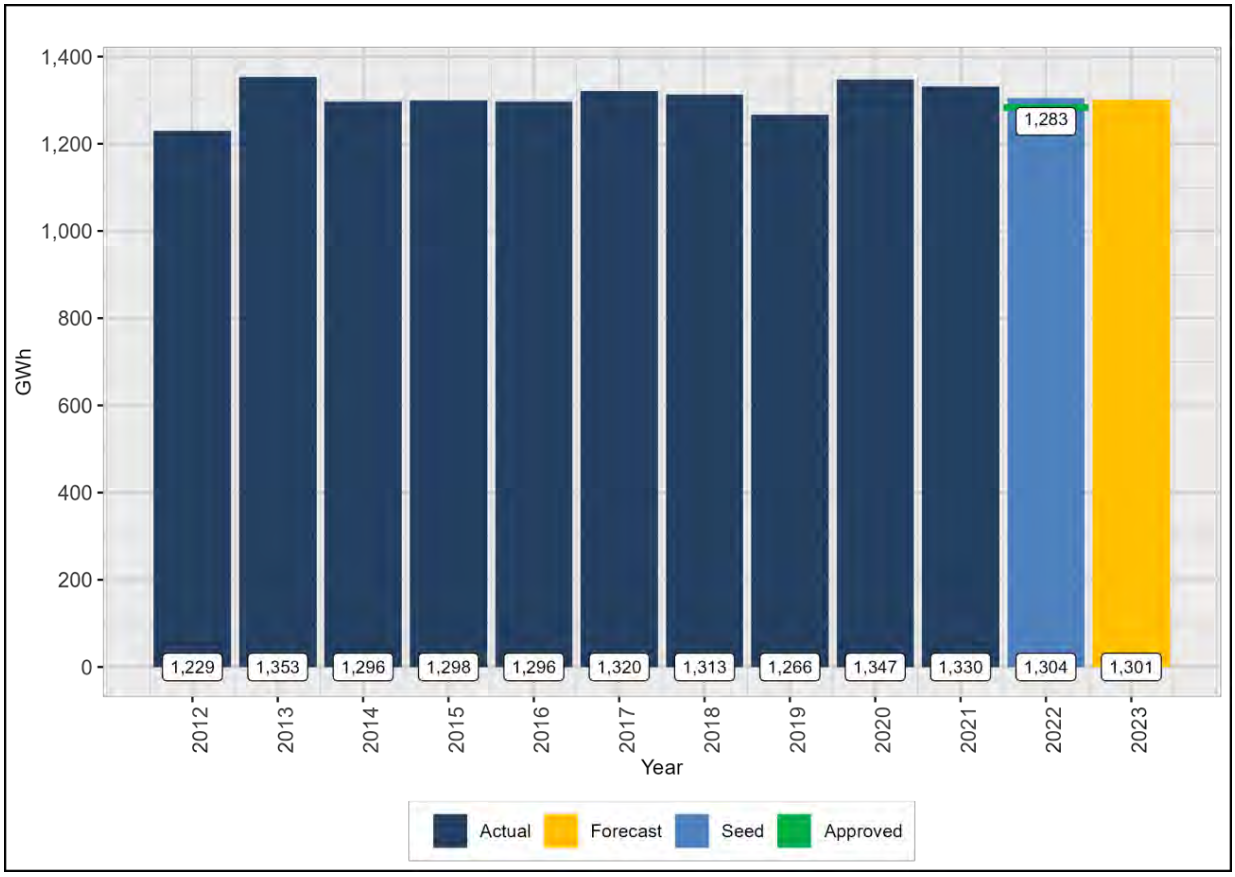


3.4.1.3 Residential Load

Consistent with past practice, the total before-savings load for the residential class is the product of the average annual residential customer count multiplied by the residential UPC. The after-savings load is produced by taking the before-savings load and then subtracting DSM savings.

As shown in Figure 3-4 below, residential after-DSM savings load is forecast to decrease by 3 GWh in 2023F from 2022S and increase by 18 GWh from 2022 Approved levels.

Figure 3-4: Normalized After-Savings Residential Load (GWh)

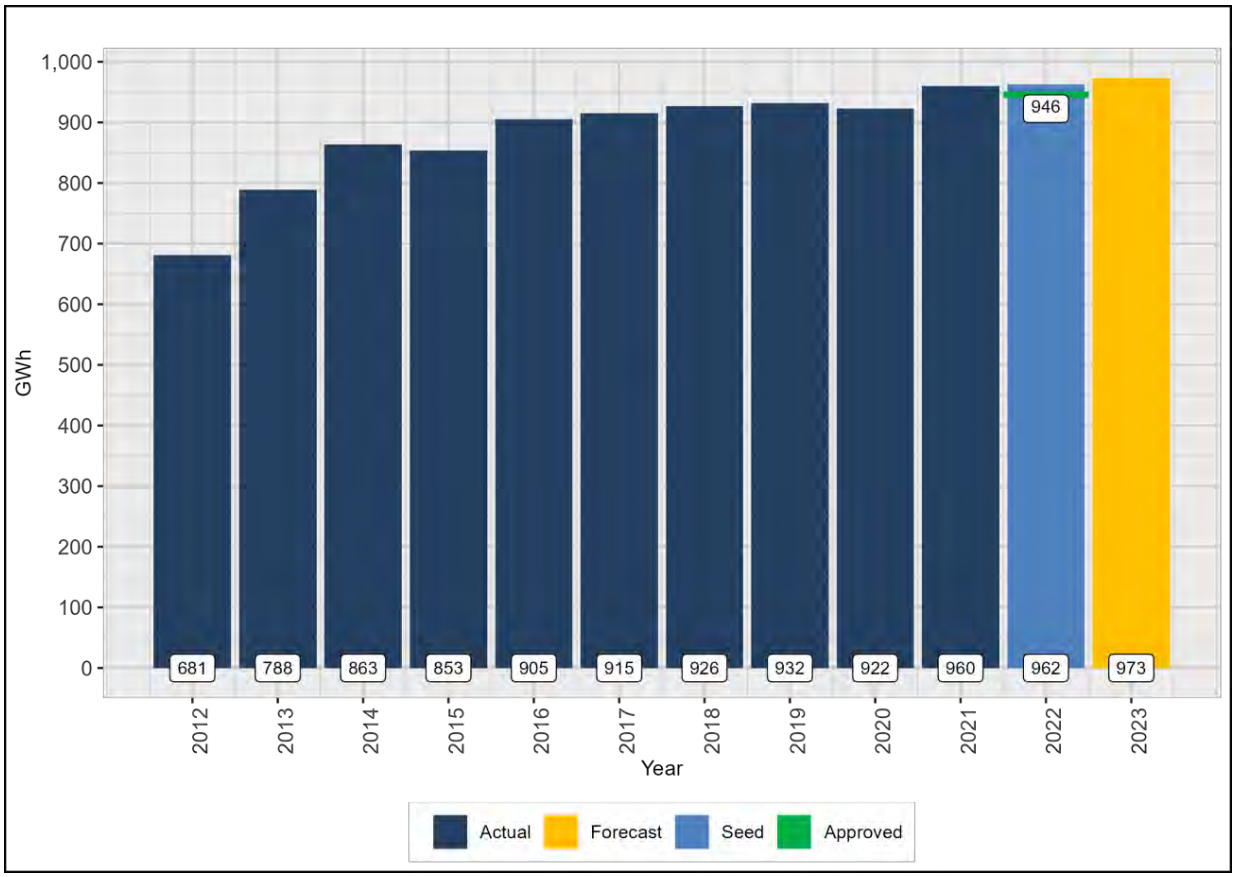


3.4.2 Commercial

3.4.2.1 Commercial Load

The commercial class is forecast based on a regression of load on the provincial GDP forecast obtained from the CBOC. The load for Electric Vehicle Direct Current Fast Chargers (EV DCFC) serviced by FBC are then added to 2022S and 2023F and account for less than a 1 GWh increase in both 2022S and 2023F. As shown in Figure 3-5 below, commercial after-savings load is forecast to increase by 11 GWh in 2023F from 2022S and increase by 27 GWh in 2023F from 2022 Approved.

Figure 3-5: After-Savings Commercial Load (GWh)



3.4.3 Wholesale

FBC sells wholesale power to municipalities for service to certain customers within its service territory that own and operate their own electrical distribution systems, and to BC Hydro. The wholesale customers' load composition is a combination of residential, commercial, industrial and lighting.

Consistent with past practice, the wholesale class is forecast using survey information from each of the individual wholesale customers, as the individual wholesale customers are best able to forecast their future load growth. For 2023, all but one of the wholesale customers responded with their load forecast projections.

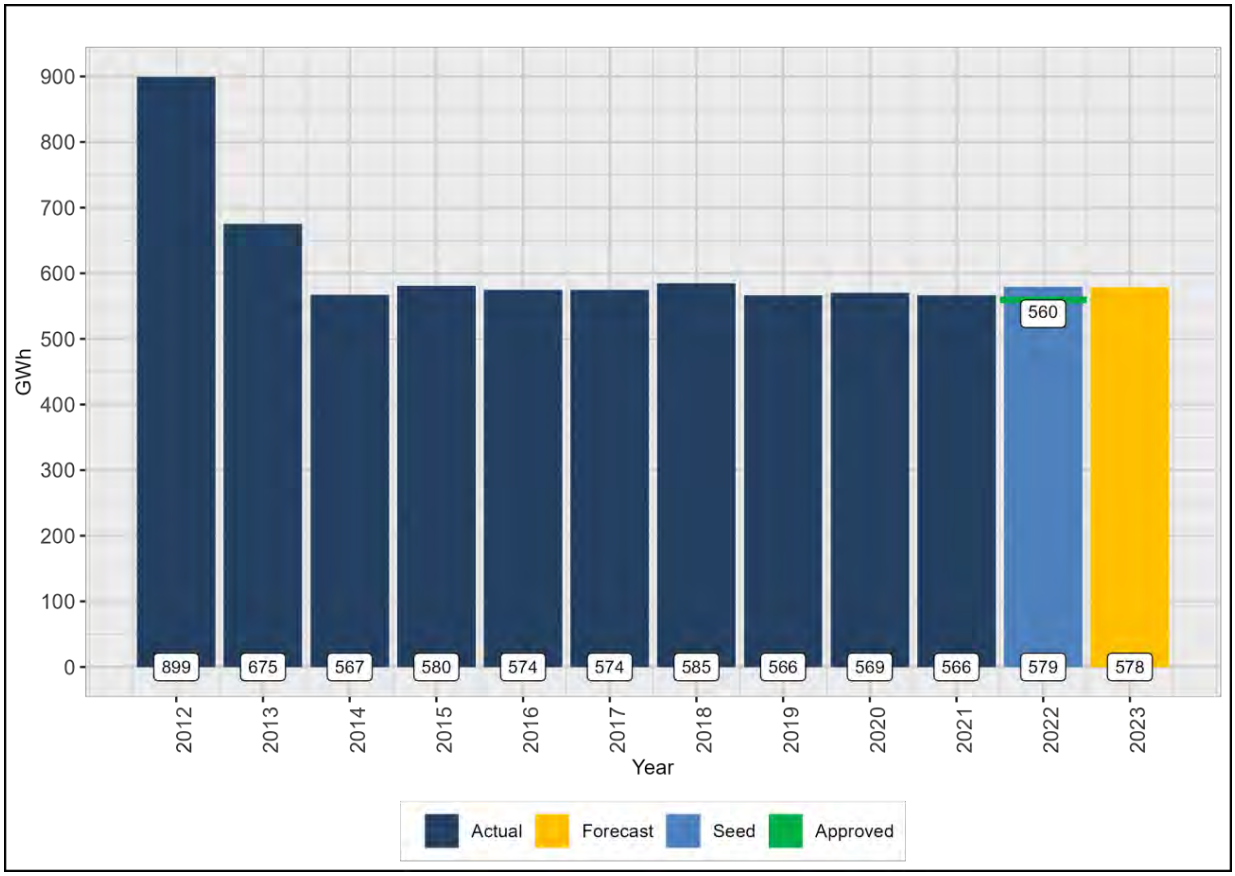
In the Annual Review for 2022 Rates Decision, the BCUC Panel directed FBC "to provide any efforts it has undertaken to improve the accuracy of its forecasts of wholesale customer load in the 2023 Annual Review, including the results of such efforts."[8] The BCUC Panel further requested that FBC work more closely with wholesale customers to develop more accurate forecasts. As such, in April of this year, FBC met with the City of Penticton, the District of

[8] FBC Annual Review for 2022 Rates Decision and Order G-374-21, p. 32.

Summerland and the City of Nelson to discuss load forecast methods, techniques and tools, as well as each City's/District's individual load forecasts. Both FBC and the Cities/District found the workshops to be informative and productive, and FBC intends to continue to conduct these workshops on an annual basis in the future.

As shown in Figure 3-6 below, after-savings wholesale load is forecast to decrease by 1 GWh in 2023F from 2022S and increase by 18 GWh in 2023F from 2022 Approved.

Figure 3-6: Normalized After-Savings Wholesale Load (GWh)



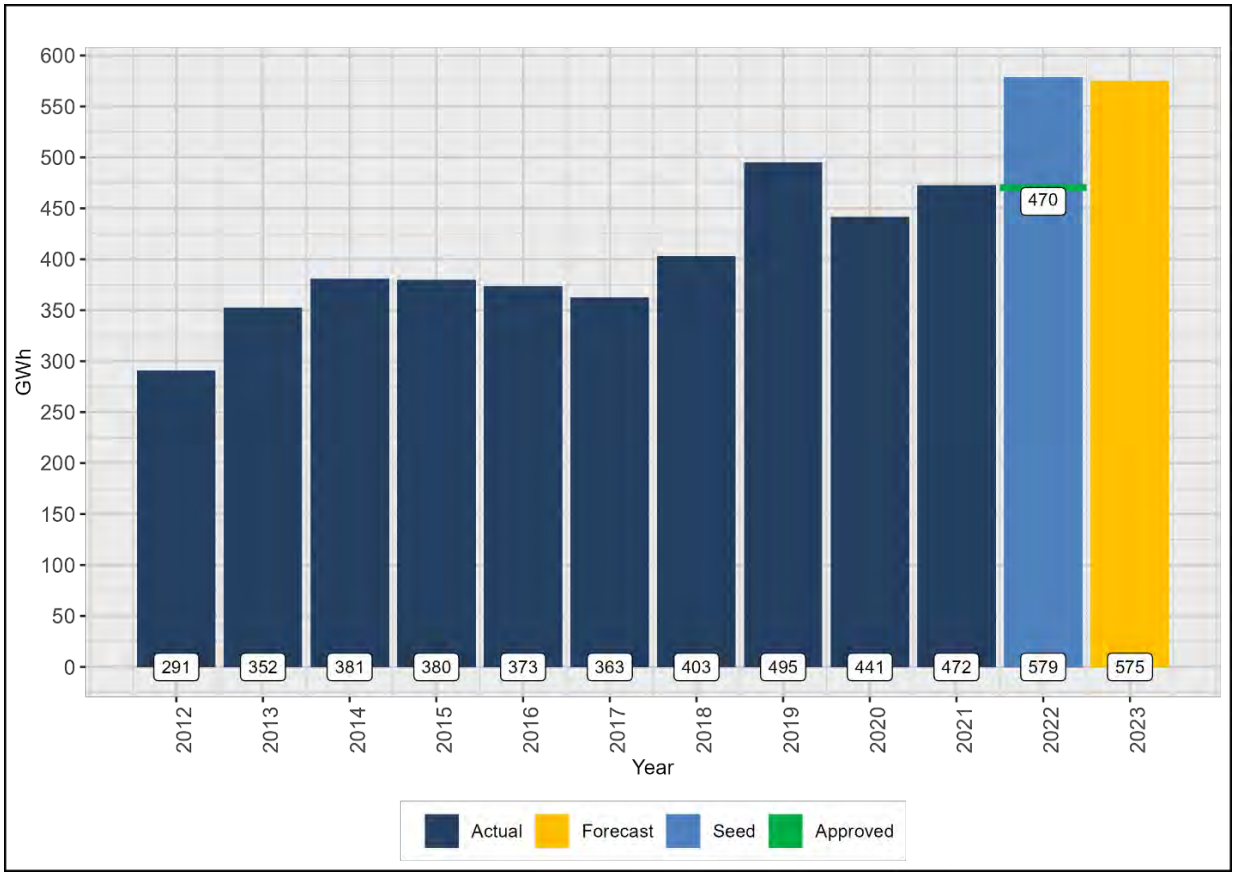
3.4.4 Industrial

Consistent with past practice, the industrial forecast is determined through a combination of customer load surveys and, when not available, escalation of the most recent annual loads by the corresponding provincial GDP growth rates for individual industries.

FBC sends all existing industrial customers a load survey that requests the customer's anticipated use for the next five years. A survey is used because individual industrial customers have the best understanding of what their future load will be. This year FBC received a response from 81 percent (34 of 42) of the surveys sent out. The responding customers represent approximately 90 percent of the total industrial load.

As shown in Figure 3-7 below, after-savings industrial load is forecast to decrease by 4 GWh in 2023F when compared to 2022S and increase by 105 GWh in 2023F compared to 2022 Approved. The increased forecast in 2022S and 2023F compared to 2022 Approved is primarily due to projected increases in data centre loads.

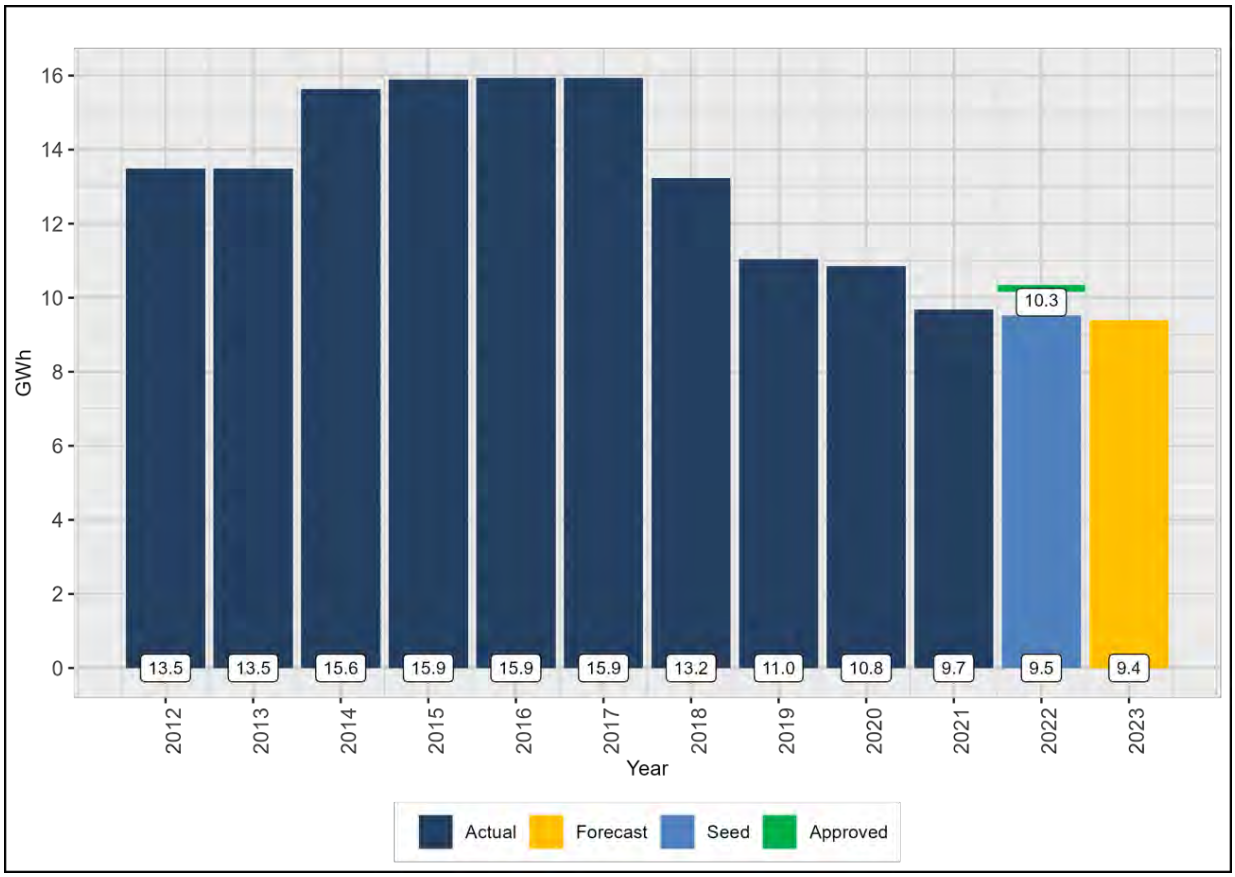
Figure 3-7: After-Savings Industrial Load (GWh)



3.4.5 Lighting

Due to the implementation of LED streetlights, the lighting load has seen declines for the past four years. FBC used the 2021 Actuals as the forecast for this load and then reduced it by DSM savings. As shown in Figure 3-8 below, after-savings lighting load is forecast to decrease by 0.1 GWh in 2023F from 2022S and decrease by 0.9 GWh when compared to 2022 Approved.

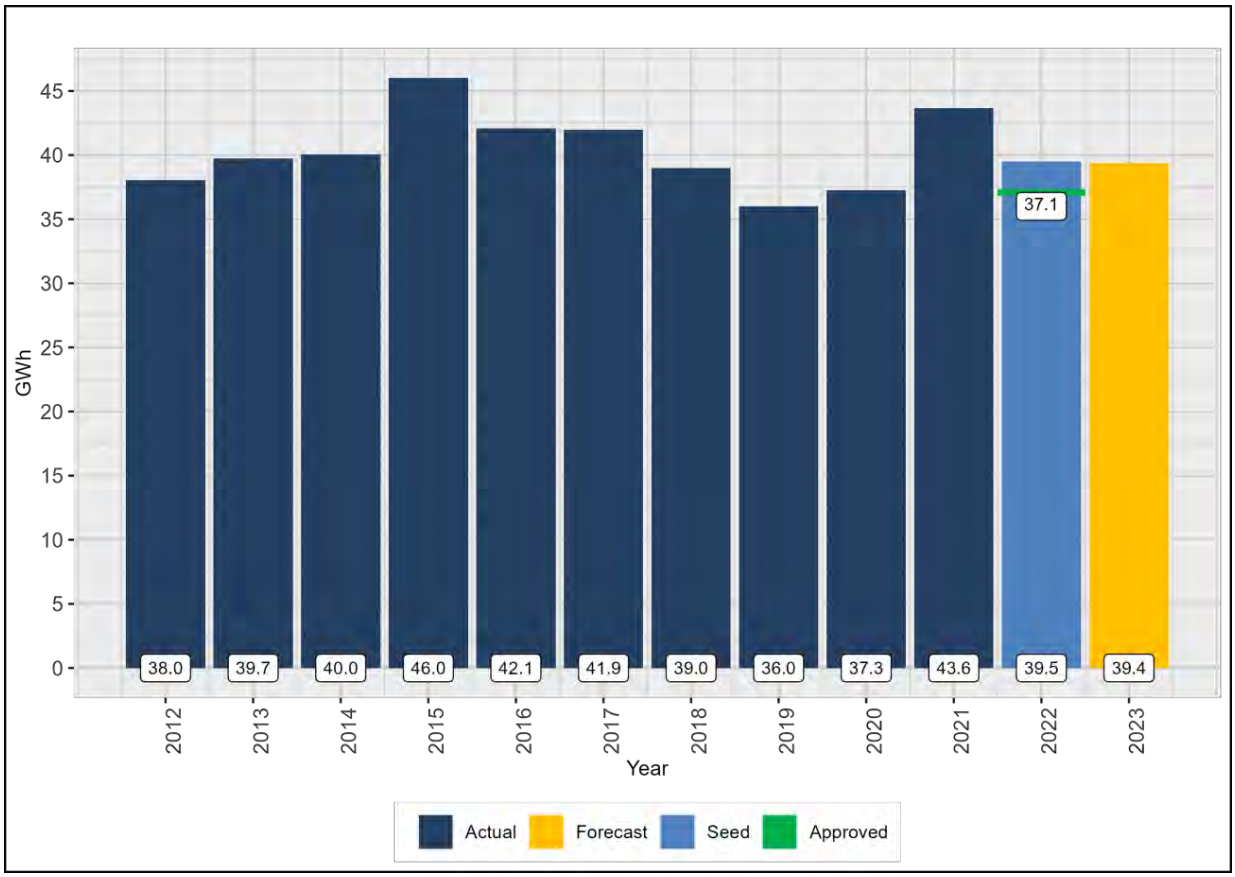
Figure 3-8: After-Savings Lighting Load (GWh)



3.4.6 Irrigation

Due to the variability in the load in the recent historical data, FBC used a five-year average as the forecast for the irrigation load. As shown in Figure 3-9 below, after-savings irrigation load is forecast to decrease 0.1 GWh from 2022S to 2023F and increase by 2.3 GWh in 2023F when compared to 2022 Approved.

Figure 3-9: After-Savings Irrigation Load (GWh)



3.4.7 Losses and Company Use

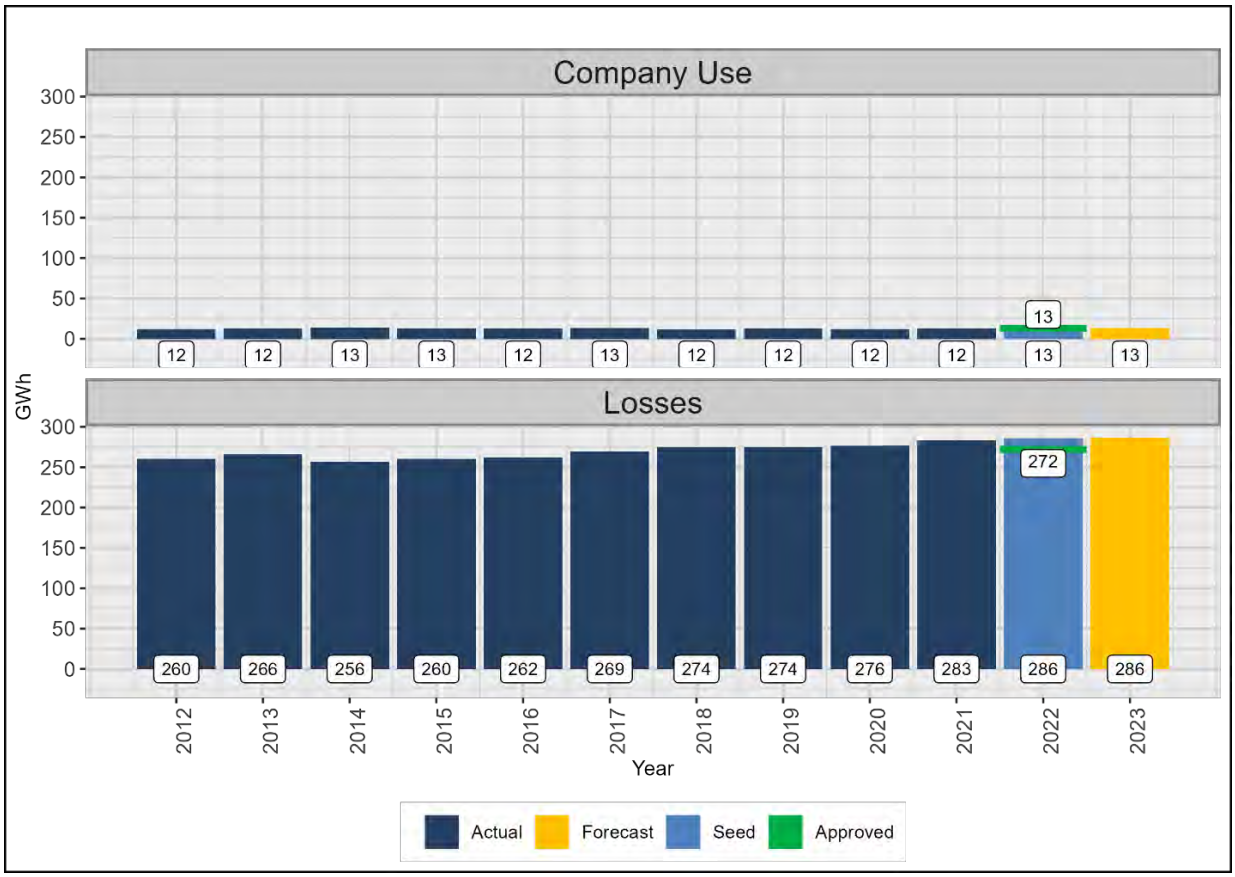
FBC conducted a Losses Study in 2019[9] and, consistent with that study, has assumed a loss rate of 7.6 percent of gross load (excluding company use). System losses consist of:

- Losses in the transmission and distribution system;
- Losses due to wheeling through the BC Hydro system; and
- Unaccounted-for load (meter inaccuracies and theft).

As shown in Figure 3-10 below, after-savings load losses are forecast to remain constant in 2023F because the gross load is forecast to be relatively stable when compared to 2022S. When compared to 2022 Approved, the 2023F after-savings load losses are forecast to increase by 14 GWh due to increased load. FBC has separated company use in the graph below, which is forecast at 13 GWh per year in 2023F, consistent with 2022S.

[9] MRP Application, Exhibit B-1-1, Appendix B3.

Figure 3-10: Normalized After-Savings Load Losses (GWh)



3.4.8 Peak Demand

The peak demand forecast is produced using the 10-year average of historical peaks, including peaks from the June 2021 “heat dome” event. The historical peak data is escalated by the gross load growth rate before it is averaged to account for the growth of demand on the FBC system.

Normalized after-savings historical winter and summer peaks are shown below along with 2022S and 2023F. The peaks shown below are seasonal, where the winter peak can fall in either November or December of the current year or January and February of the following year, while the summer peak falls in June, July or August of the current year.

Figure 3-11: After-Savings Winter Peaks (MW)

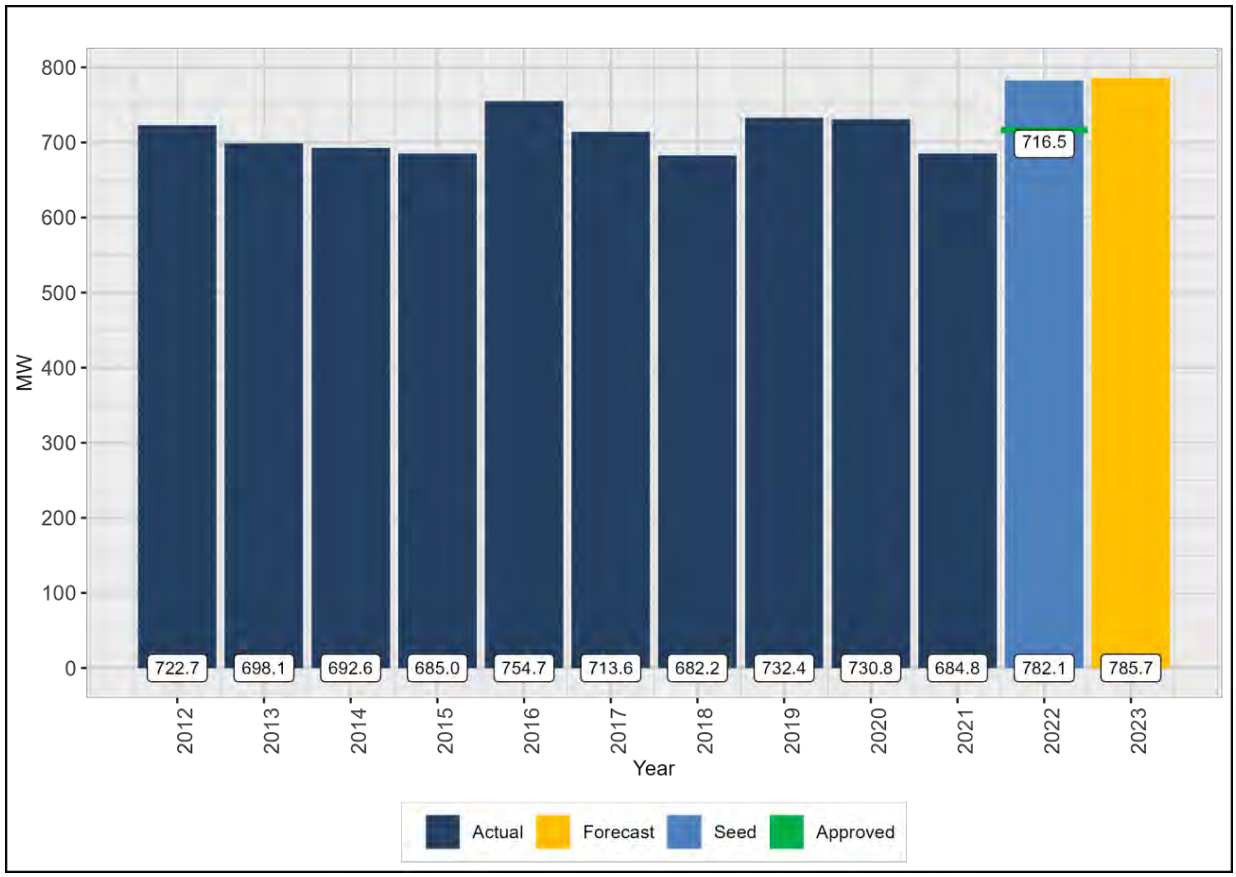
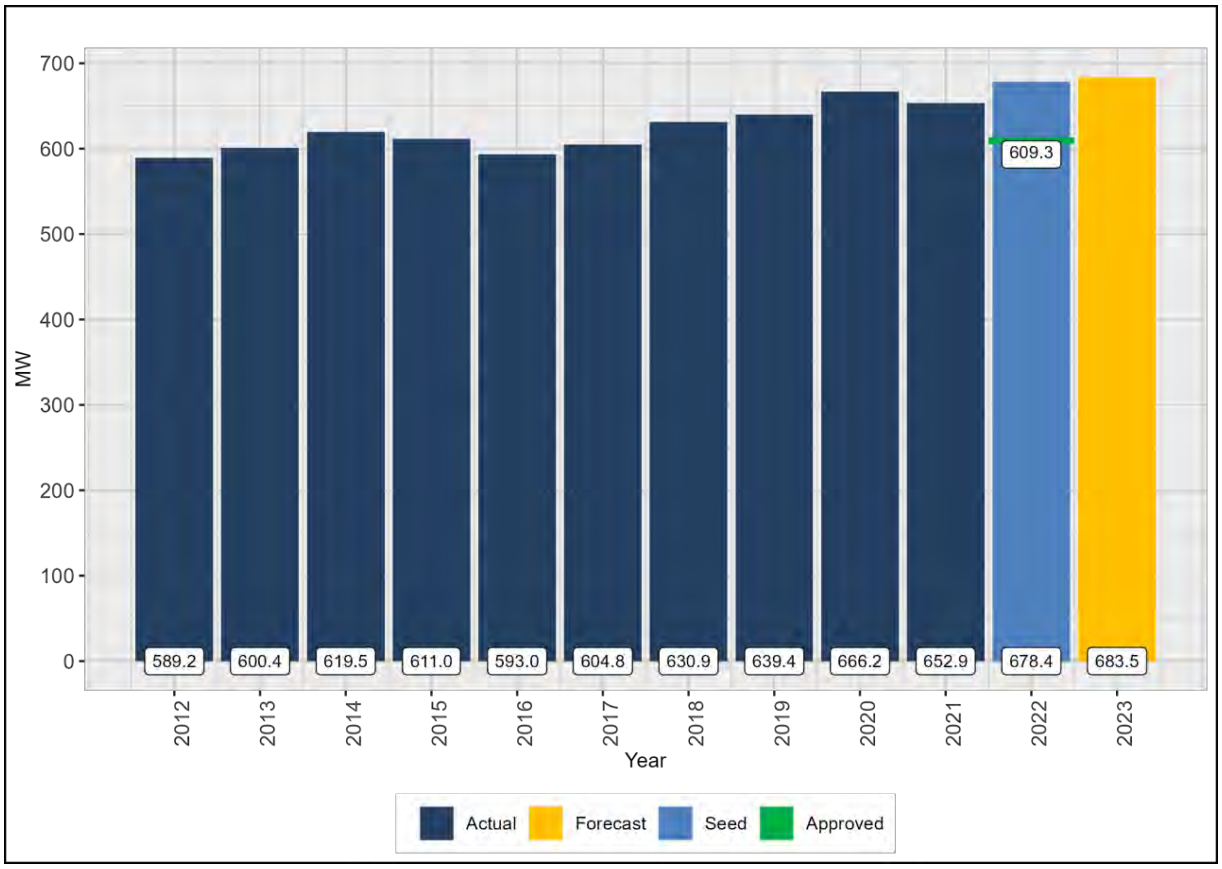


Figure 3-12: After-Savings Summer Peaks (MW)



3.5 *CUSTOMER FORECAST*

Table 3-3 shows the actual and forecast year-end customer count by rate class. The residential and commercial customer counts are forecast using the methods described in Sections 3.4.1 and 3.4.2, respectively. Industrial customers are forecast based on information on expected new loads provided by key account managers. The lighting customer forecast is prepared using a three-year regression of year-end customer counts. Wholesale and irrigation customer counts are assumed to remain at 2021 levels.

Overall, for 2023F, FBC is forecasting customer growth of 2.1 percent compared to 2022S and growth of 2.4 percent compared to 2022 Approved.

Table 3-3: Year-End Direct Customer Count

Line No.	Description	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022S	2023F
1	Residential	99,228	111,862	113,431	114,166	115,772	117,748	120,291	122,465	124,966	126,678	129,336	132,015
2	Commercial	11,811	13,662	14,363	14,976	15,073	15,398	15,678	15,956	16,165	16,594	16,995	17,496
3	Wholesale	7	6	6	6	6	6	6	6	6	6	6	6
4	Industrial	39	47	49	50	50	50	52	51	43	42	42	42
5	Lighting	1,739	1,644	1,620	1,590	1,559	1,511	1,482	1,467	1,443	1,407	1,379	1,349
6	Irrigation	1,091	1,097	1,103	1,095	1,090	1,080	1,078	1,082	1,091	1,103	1,103	1,103
7	**Total**	113,915	128,318	130,572	131,883	133,550	135,793	138,587	141,027	143,714	145,830	148,861	152,011

3.6 REVENUE FORECAST

The forecast of revenues has been developed by applying approved 2022 rates to the forecast billing determinants for each customer class.

Table 3-4 below summarizes the 2022 Approved, 2022 Projected and 2023 Forecast sales revenue.

Table 3-4: Forecast Sales Revenue at Approved Rates ($ millions)[10]

Line No.	Description	Approved 2022	Projected 2022	Forecast 2023
1	Residential	$ 195.058	$ 200.837	$ 197.962
2	Commercial	104.380	107.153	106.230
3	Wholesale	51.255	53.722	52.031
4	Industrial	40.804	46.764	47.856
5	Lighting	2.411	2.266	2.207
6	Irrigation	3.386	3.550	3.554
7	Total	$ 397.294	$ 414.292	$ 409.840

When comparing the 2022 Approved to 2022 Projected there is an increase in revenue of $16.998 million, the majority of which is due to increased residential and industrial loads.

The 2023 Forecast revenue is $12.546 million higher than 2022 Approved, primarily due to an increase in the industrial load, followed by small increases in the residential, commercial, and wholesale loads. These increases are slightly offset by a decrease in the lighting load resulting from the continued conversion to LED streetlights in the FBC service territory.

Variances between the revenue forecast in this section and the actual revenues realized are captured in the Flow-through deferral account.

3.7 SUMMARY

The normalized after-savings gross load forecast for 2023F is 3,775 GWh. Based on net load of 3,476 GWh at the approved 2022 rates, FBC's 2023 revenue forecast is $409.840 million. When comparing 2023F to 2022 Approved, there is an increase in net load of 170 GWh. The net load increase in 2023F is due to increased loads in the industrial, commercial, wholesale residential and irrigation classes.

[10] The commercial sales revenue includes the revenues under RS 96 EV DCFC Stations. Please refer to Section 5.8 for further detail on EV DCFC station costs and revenues.

4. POWER SUPPLY

4.1 INTRODUCTION AND OVERVIEW

This section includes a review of the 2022 Projected and 2023 Forecast power purchase expense (PPE), wheeling expense and water fees. Collectively, the PPE, wheeling expense and water fees are referred to as the power supply cost.

As shown in Table 4-1 below, the 2023 Forecast power supply cost of $182.105 million represents an increase of 12.5 percent or $20.275 million compared to the 2022 Approved cost of $161.830 million. The increase in 2023 Forecast power supply cost is mainly due to increases in PPE, however, wheeling expense has increased as well. The 2023 Forecast PPE has increased as a result of increased gross load and a reduction in wholesale market purchases, which has resulted in a correspondingly greater reliance on energy supplied under BC Hydro Rate Schedule (RS) 3808. 2023 Forecast wheeling expense has increased as a result of both rates and usage. The 2023 Forecast water fee expense has decreased compared to 2022 Approved as a result of decreased usage.

Any variances between forecast and actual power supply costs are recorded in the Flow-through deferral account and returned to or recovered from customers in the subsequent year.

Table 4-1: Power Supply Cost ($ millions)

Line No.	Description	Approved 2022	Projected 2022	Forecast 2023
1	Power Purchase Expense	$ 143.779	$ 153.164	$ 163.575
2	Wheeling Expense	6.093	6.330	6.987
3	Water Fees	11.958	11.916	11.543
4	Total Power Supply Cost	$ 161.830	$ 171.409	$ 182.105
5				
6	Gross Load (GWh)	3,591	3,786	3,775

4.2 SUMMARY OF POWER SUPPLY RESOURCES

FBC uses a combination of Company-owned generation entitlements, firm contracted supply, and market purchases to meet its load requirements. The Company's firm resources consist of:

1. Canal Plant Agreement (CPA) Entitlements associated with the generation facilities owned by FBC. The costs associated with FBC-owned generation are not included in the power purchase estimates, except for the Balancing Pool adjustments, which account for year-to-year timing differences in the entitlement energy storage under the CPA;
2. The Brilliant Power Purchase Agreement (BPPA), a 125 MW contract (Order E-7-96), and an amendment to the BPPA which reflects the purchase of 20 MW of Brilliant Upgrade

power (Letter L-57-00), and the 5 MW Brilliant Tailrace Capacity agreement (Order E-17-01);

3. A power purchase agreement (PPA) with BC Hydro (a 200 MW contract) under BC Hydro RS 3808 (Order G-60-14);
4. The Waneta Expansion Capacity Purchase Agreement (WAX CAPA), which is a 40-year purchase agreement with the Waneta Expansion Limited Partnership for capacity entitlements under the CPA (Orders E-29-10 and E-15-12);
5. A number of small Independent Power Producer (IPP) contracts; and
6. A number of market purchase arrangements.

4.3 *PORTFOLIO OPTIMIZATION*

The primary objectives of FBC's power supply portfolio planning are to ensure that the Company has sufficient firm resources to meet expected load requirements, to ensure the availability of cost-effective reliable power for FBC's customers, to prudently manage exposure to the cost and availability of market power supplies, and to optimize the value of any surplus resources that are not needed to meet load requirements.

The Company currently has long-term, firm resources from which it can supply all of its 2023 forecast annual energy requirements, and most of its forecast capacity requirements with the exception of a small number of hours during June and July. These forecast capacity gaps result from the Company's updated, increased load forecast. As mentioned in previous Annual Reviews, the nature of FBC's contracted resources, in particular the BC Hydro PPA, provides the Company some flexibility to participate in the market when conditions are favourable to mitigate the cost of holding those firm resources. However, in contrast to recent years, the regional electricity market has experienced a step change over the past year due to several factors that include resource adequacy concerns, increased natural gas prices, and increased severe weather events. This change in the market price environment has resulted in little opportunity to displace PPA purchases on a forward basis. Furthermore, although FBC's load requirements are forecast to grow over time, the amount of capacity provided under the WAX CAPA is currently greater than FBC's capacity requirements in most months, and FBC sells the surplus capacity to mitigate power purchase expense. FBC has contracted to release a 50 MW block of capacity purchased under the WAX CAPA to BC Hydro under the Residual Capacity Agreement (RCA), which was approved by Order G-161-14. The remaining surplus WAX CAPA will be sold to Powerex Corp. (Powerex) on a day-ahead basis, if and when it is not required to meet FBC load requirements. These sales are made under the Capacity and Energy Purchase and Sale Agreement (CEPSA) with Powerex dated February 17, 2015, and accepted by Order E-10-15.

4.4 *FBC 2022/23 ANNUAL ELECTRIC CONTRACTING PLAN*

On May 2, 2022, FBC filed its 2022/23 Annual Electric Contracting Plan (AECP) with the BCUC. The purpose of the AECP is to outline FBC's plan to meet its peak demand requirements and

annual energy requirements for the operating year commencing October 1, 2022 and ending September 30, 2023, and to facilitate FBC's annual energy nomination under the PPA. FBC is required to take or pay for 75 percent of the PPA Nomination, regardless of whether it schedules the energy. The difference between the PPA Nomination and the 75 percent minimum take provides flexibility to manage annual loads that are below forecast or to displace PPA purchases with lower cost market purchases. Therefore, real-time opportunities to displace PPA purchases are restricted to a maximum of 25 percent of the PPA nominated energy, but could be more or less, depending on system conditions.[11] The AECP also outlines FBC's load and resource balance over the following four years, and FBC's plan for optimizing its portfolio over that period. FBC's forecasts of PPE for the remainder of 2022 and for 2023 are based on the plan detailed in the 2022/23 AECP, which was accepted by the BCUC on May 26, 2022, by Letter L-19-22.[12]

The AECP identified FBC's intention to make its annual energy nomination under the PPA for the 2022/23 contract year equal to 767 GWh, less any firm market contracts that FBC could enter into, as described in Section 5 of the 2022/23 AECP. Prior to the June 30, 2022 nomination deadline, FBC updated its forecast load and resource balance for the 2022/23 contract year and submitted a nomination of 774 GWh.

4.5 *2022 PROJECTED POWER PURCHASE EXPENSE*

As shown in Table 4-2 below, FBC's 2022 Projected gross load (after taking into account demand side management and other customer savings) is expected to be 195 GWh above the 2022 Approved value, and PPE is projected to be above the 2022 Approved value by $9.385 million. The increase in 2022 Projected PPE is primarily due to the increase in gross load above the 2022 Approved value. This increase in gross load drives increases in both the BC Hydro PPA and wholesale market expense to meet the additional load. In addition, increases in both the purchase price under the BC Hydro PPA and the average cost of purchases from the market further contributed to the increase in PPE.

[11] For example, if loads were 50 GWh lower in a year than forecast, that must be adjusted for as part of the 25 percent PPA flexibility such that the amount of PPA energy that can be displaced by market purchases is also reduced by 50 GWh.

[12] The AECP was filed confidentially. The non-confidential Executive Summary is attached to Letter L-19-22.

Table 4-2: 2022 Power Purchase Expense ($ millions)

Line No.	Description	Approved 2022	Projected 2022	Difference
1	Brilliant	$ 41.841	$ 42.367	$ 0.526
2	BC Hydro PPA	44.062	49.539	5.477
3	Waneta Expansion	42.701	41.434	(1.267)
4	Market and Contracted Purchases	15.102	21.672	6.570
5	Independent Power Producers	0.073	0.058	(0.015)
6	Self-Generators	-	-	-
7	CPA Balancing Pool	-	(1.252)	(1.252)
8	Transmission Service Loss Recoveries	-	-	-
9	Special and Accounting Adjustments	-	(0.654)	(0.654)
10	Total	$ 143.779	$ 153.164	$ 9.385
11				
12	Gross Load (GWh)	3,591	3,786	195

4.6 *2023 FORECAST POWER PURCHASE EXPENSE*

As shown in Table 4-3 below, the 2023 Forecast PPE is $10.412 million greater than the 2022 Projected. The forecast increase from $153.164 million in 2022 to $163.575 million in 2023 is mainly a result of a reduction in market and contracted purchases as they increase in price and correspondingly, a greater reliance on energy supplied by BC Hydro as it becomes more cost effective compared to market. Furthermore, as a result of load growth and uneconomic wholesale market prices, FBC expects to take Tranche 1 PPA energy over the nominated amount during 2023. Tranche 1 PPA energy taken over the nominated amount costs 150 percent of the Tranche 1 embedded cost rate,[13] and this exposure to more expensive PPA energy is also contributing to increased costs. Also contributing to the increase are escalations to the Waneta Expansion and Brilliant contract rates.

Table 4-3 below shows a comparison of the 2022 Projected and 2023 Forecast PPE. Reasons for significant variances from the 2022 Projected PPE are discussed below.

[13] $50.94 per MWh x 150 percent = $76.41 per MWh.

Table 4-3: 2023 Forecast Power Purchase Expense ($ millions)

Line No.	Description	Projected 2022	Forecast 2023	Difference
		-		
1	Brilliant	$ 42.367	$ 44.050	$ 1.683
2	BC Hydro PPA	49.539	71.302	21.763
3	Waneta Expansion	41.434	41.834	0.400
4	Market and Contracted Purchases	21.672	6.326	(15.346)
5	Independent Power Producers	0.058	0.062	0.004
6	Self-Generators	-	-	-
7	CPA Balancing Pool	(1.252)	-	1.252
8	Transmission Service Loss Recoveries	-	-	-
9	Special and Accounting Adjustments	(0.654)	-	0.654
10	Total	$ 153.164	$ 163.575	$ 10.412
11				
12	Gross Load (GWh)	3,786	3,775	(11)

4.6.1 Brilliant

Brilliant expense is forecast to increase in 2023 by $1.683 million compared to 2022 Projected due to increased rates, which are based on a forecast of the operating and maintenance cost of the plant, as well as a true-up to the prior year's actual costs compared to forecast.

4.6.2 BC Hydro PPA

BC Hydro PPA expense is forecast to increase in 2023 by $21.763 million compared to the 2022 Projected expense. The drivers of the increase are a higher purchased volume (371 GWh), which increases the expense by $21.775 million, and an increase in BC Hydro rates, which accounts for an increase of $3.987 million, for a total of $25.763 million. FBC has decreased its 2023 Forecast of PPA expense by $7.000 million in savings to account for potential real-time opportunities to displace PPA purchases with lower cost market purchases. The 2022 Projected BC Hydro expense was reduced by $3.000 million to account for potential real-time opportunities during the remainder of 2022. This results in a variance between 2022 Projected and 2023 Forecast of $21.763 million[14], as shown in Table 4-3. Actual market savings for the remainder of 2022 and 2023 may be higher or lower and will depend on system and market conditions at the time. Any variance, including these savings, is recorded in the Flow-through deferral account and returned to or recovered from customers in a subsequent year.

4.6.3 Waneta Expansion

The $0.400 million increase in Waneta Expansion expense is due to the 2.1 percent annual fixed escalation of WAX CAPA rates, offset by a $0.291 million increase in forecast surplus sales revenue under the RCA and CEPSA. Revenue under the CEPSA is linked to the amount of

[14] $21.763 million is calculated as follows: Total increase of $25.763 million less the $4.000 million variance between the 2022 Projected and 2023 Forecast real-time opportunities, or, $25.763 million – ($7.000 million - $3.000 million).

capacity FBC releases to Powerex and the day-ahead market prices at the Mid-Columbia River (Mid-C) trading hub. The Mid-C is the largest electricity trading hub in the Pacific Northwest and is located on the US portion of the Columbia River. FBC's forecast of Mid-C forward market prices is based on contracts that have been traded and/or bids and offers from forward contracts on the Intercontinental Exchange Inc. (ICE), which is a global exchange, clearing, financial data, and technology company. The method used to forecast market prices and surplus sales is the same as in the Annual Review for 2022 Rates. The forecast of surplus capacity sales revenue in 2023, which is included in line 3 of Table 4-3, is approximately $10.700 million.

4.6.4 Market and Contracted Purchases

The $15.346 million decrease in Market and Contracted Purchases forecast for 2023 is due to a lesser volume purchased at higher rates when compared to 2022 Projected. Market and Contracted Purchases for 2022 Projected include both fixed price contracted purchases and real-time market purchases made using the 25 percent flexibility of the PPA. All of the market purchases included in the 2023 Forecast are based on fixed price contracts executed by the Company, with the exception of forecast real-time market purchases for Rate Schedule 37[15] load. As discussed above in the BC Hydro PPA variance explanation, there may be opportunities for additional real-time market purchases using the flexibility of the PPA purchases.

4.6.5 CPA Balancing Pool

The CPA Balancing Pool represents timing differences in entitlement energy storage under the CPA and is used to manage fluctuations in load and resource availability, or to take advantage of market opportunities. In the 2022 Projected PPE, FBC has stored a net total of 25 GWh of entitlement energy, valued at $1.252 million. For the 2023 Forecast, and consistent with past practice, FBC does not forecast any net use or storage of entitlement energy.

4.7 *TRANSMISSION SERVICE LOSS RECOVERIES*

Transmission service customers taking service under FBC's Rate Schedules 100 and 101 currently physically deliver energy to FBC to compensate for the losses that are incurred on FBC's system as a result of wheeled energy. FBC includes transmission wheeling losses in its load forecast (included in Tables 4-2 and 4-3, line 8), and also includes loss recovery as a firm resource. Because the recoveries are delivered physically, there is no associated cost or revenue. Table 4-4 shows the 2022 and 2023 loss recoveries.

[15] RS 37 is large commercial stand-by service, which is on-demand back-up and maintenance service provided to self-generating customers. This service is provided to the customer at an hourly market-based rate, reflective of FBC's cost of supply. FBC procures this supply on a real-time basis because there is little certainty as to when customers will use this service. Forecast RS 37 load for 2023 is 15 GWh or 0.4 percent of total gross load.

Table 4-4: Transmission Service Loss Recoveries (GWh)

Line No.	Description	Approved 2022	Projected 2022	Forecast 2023
1	Loss Recoveries	12	12	12

4.8 WHEELING EXPENSE

Wheeling expense includes wheeling service provided by BC Hydro under the Amended and Restated Wheeling Agreement (ARWA) and Open Access Transmission Tariff (OATT) as needed to supply the Company's loads in the Okanagan, Creston and Princeton. Also included are charges paid to Teck Metals Ltd. (Teck) for the use of its 71 Line. Rates under the ARWA are specified in BC Hydro's RS 3817.

Wheeling expense is forecast using the same method as in the Annual Review for 2022 Rates. Table 4-5 below shows FBC's Wheeling Expense for 2022 and 2023.

Table 4-5: Wheeling Expense ($ millions)

Line No.	Description	Approved 2022	Projected 2022	Forecast 2023
1	Wheeling Nomination (MW Months)			
2	Okanagan Point of Interconnection	2,475	2,475	2,670
3	Creston	420	420	420
4				
5	Wheeling Expense			
6	Okanagan Point of Interconnection	$ 4.903	$ 4.976	$ 5.555
7	Creston	0.542	0.550	0.570
8	Other	0.648	0.804	0.863
9	Total Wheeling Expense	$ 6.093	$ 6.330	$ 6.987

Total 2022 Projected wheeling expense is $0.237 million greater than 2022 Approved. The 2022 Projected ARWA costs are $5.526 million (lines 6 and 7 in the table above), a $0.081 million increase when compared to 2022 Approved, which is a result of higher than expected BC-CPI and therefore ARWA rates. 2022 Projected Teck and OATT wheeling costs are $0.804 million (line 8 above), which is $0.156 greater than 2022 Approved. This is mainly due to increased use of OATT wheeling.

2023 Forecast wheeling expense is $0.657 million higher than 2022 Projected. This is a result of both increased use and rates. FBC increased the Okanagan wheeling nomination to 2,670 MW months in 2023 from 2,475 MW months in 2022. ARWA rates are forecast to increase on October 1 of both 2022 and 2023, based on forecast BC-CPI, as is the Teck wheeling rate as a result of a letter agreement made between Teck and FBC.

4.9 WATER FEES

Water fees are based on FBC's entitlement usage in the previous year and the rate increases are indexed to BC-CPI.

As shown in Table 4-6 below, the 2023 Forecast water fees are decreasing by $0.373 million from the 2022 Projected due to decreased entitlement use. 2023 water fees are forecast using the same method as in the Annual Review for 2022 Rates.

Table 4-6: Water Fees ($ millions)

Line No.	Description	Approved 2022	Projected 2022	Forecast 2023
1	Plant Entitlement in Previous Year (GWh)	1,679	1,663	1,571
2				
3	Water Fees	$ 11.958	$ 11.916	$ 11.543

4.10 SUMMARY

The primary objectives of FBC's power supply portfolio planning are to ensure that the Company has sufficient firm resources to meet expected load requirements, to ensure the availability of cost-effective reliable power for FBC's customers, to prudently manage exposure to the cost and availability of market power supplies, and to optimize the value of any surplus resources that are not needed to meet load requirements.

FBC's forecast of PPE is based on FBC's firm resources in place at the time of filing and is consistent with the 2022/23 AECP. Any variances in the power supply cost, including any decreases in PPE due to further portfolio optimization, are recorded in the Flow-through deferral account and returned to or recovered from customers in a subsequent year.

5. OTHER REVENUE

5.1 INTRODUCTION AND OVERVIEW

This section discusses FBC's forecasts of Other Revenue. In the MRP Decision (page 74), FBC was approved for variances between forecast and actual Other Revenue to be subject to earnings sharing.[16]

FBC is forecasting Other Revenue for 2023 to be $0.409 million higher than 2022 Approved, primarily due to higher Late Payment Charges and expected annual increases in rates for Apparatus and Facilities Rental, Contract Revenue and Transmission Access Revenue.

2022 Projected Other Revenue is $1.335 million higher than 2022 Approved. The main drivers of this increase are the sales of carbon credits related to Electric Vehicle (EV) Direct Current Fast Charging (DCFC) stations, as well as higher Contract Revenue and Late Payment Charges.

Table 5-1: Other Revenue ($ millions)

Line No.	Description	Approved 2022	Projected 2022	Forecast 2023
1	Apparatus and Facilities Rental	$ 6.018	$ 6.018	$ 6.108
2	Contract Revenue	2.277	2.750	2.367
3	Transmission Access Revenue	1.771	1.788	1.834
4	Interest Income	0.020	0.020	0.030
5	Late Payment Charges	0.875	1.095	0.994
6	Connection Charges	0.505	0.505	0.553
7	EV Stations Carbon Credits	-	0.625	-
8	Other Recoveries	0.366	0.366	0.355
9	Total Other Revenue	$ 11.832	$ 13.167	$ 12.241

In the following sections, FBC summarizes its projections and forecasts for each of the line items included in the table above.

5.2 APPARATUS AND FACILITIES RENTAL

Apparatus and Facilities Rental is comprised primarily of pole contact revenue from other utilities and businesses that attach their facilities to FBC infrastructure in order to deliver services to their customers, such as telephone and cable television providers. Rent is charged at a unit rate per pole contact multiplied by the number of poles that are contacted. There are no variances projected in 2022 compared to 2022 Approved, as final amounts have yet to be calculated since the majority of invoices are issued during the third quarter of the year. The 2023 Forecast is higher than 2022 Approved due to expected escalations in unit rental rates for continuing contracts.

[16] Variances in Other Revenue associated with Electric Vehicle (EV) stations carbon credits are treated as flow-through, as EV Direct Current Fast Charging (DCFC) stations are prescribed undertakings under section 5 of the GGRR and the cost of service associated with EV DCFC stations is subject to flow-through treatment.

5.3 CONTRACT REVENUE

FBC performs work under contract to third parties at the Waneta and Brilliant hydroelectric generating facilities. This third-party work, and the associated management fees earned, fluctuates from year to year based on customer requirements, which include routine and non-routine work planned at the start of the customer's fiscal year.

The Company also operates and maintains a number of other facilities for third-party entities through its non-regulated affiliate FortisBC Pacific Holdings Inc. (FPHI). Transactions between FBC and FPHI are conducted in accordance with FBC's Code of Conduct and Transfer Pricing Policy[17] and earn a transfer price profit revenue. Revenues may fluctuate from year to year depending on customer requirements.

The 2022 Projected revenue is higher than 2022 Approved due to an increase in costs related to the close-out of a multi-year asset refurbishment project for a third party that began in 2020, as well as certain costs that shifted from 2021 into 2022 for the same project. The 2023 Forecast is higher than 2022 Approved due to expected increases in the average cost of work and materials recovered from third-party customers.

5.4 TRANSMISSION ACCESS REVENUE

Transmission Access Revenue represents charges to customers for transmitting power over the FBC system. The 2022 Projected revenue is slightly higher than 2022 Approved due to a higher nomination than originally forecast for one customer. The 2023 Forecast is higher than 2022 Approved due to the phased increase in rates over three years beginning January 1, 2020, as approved by Order G-40-19.

5.5 INTEREST INCOME

Interest Income is primarily comprised of DSM loan interest income, as well as other banking interest income. The Company is not forecasting significant changes in the amount of DSM loans outstanding; as a result, no significant changes in interest income are expected in 2022 Projected or the 2023 Forecast.

5.6 LATE PAYMENT CHARGES

Late Payment Charges have historically been forecast based on the average of the most recent three years of actual Late Payment Charges earned. However, due to the impact of the COVID-19 pandemic and FBC's implementation of customer relief measures, which included the suspension of Late Payment Charges until March 2021, the actual amounts collected have fluctuated from year to year.

[17] As approved by Order G-5-10A.

FBC continues to see fluctuations in Late Payment Charges. The 2022 Projected Late Payment Charges are higher than 2022 Approved by $0.220 million based on amounts charged so far in 2022 as well as growth in customers since the 2017 to 2019 period used to develop the 2022 Approved.

In consideration of the continued fluctuations being experienced, the 2023 Forecast has been calculated based on the average of 2021 Actual and 2022 Projected Late Payment Charges of $0.892 million and $1.095 million, respectively. This results in an increase in Late Payment Charges of $0.119 million compared to 2022 Approved.

5.7 CONNECTION CHARGES

Connection Charges are calculated based on the fees specified in FBC's rate schedules applicable to new customer connections or current customer reconnections. The 2022 Projected is expected to be consistent with 2022 Approved based on amounts charged so far in 2022. The 2023 Forecast is expected to be higher than 2022 Approved based on customer growth and forecast customer reconnections.

5.8 CLEAN GROWTH INITIATIVE – EV DCFC STATIONS CARBON CREDITS

FBC's EV DCFC stations are prescribed undertakings under section 5 of the GGRR[18] and the cost of service associated with EV DCFC stations is subject to flow-through treatment. The EV charging rates, the depreciation rate for EV charging stations, and the inclusion of related revenues and expenses associated with FBC's EV DCFC stations in FBC's regulated accounts were approved by the BCUC on November 24, 2021[19]. The revenues to be included in FBC's regulated accounts include the Other Revenue from the sale of carbon credits related to EV stations[20] earned under the Renewable Low Carbon Fuel Requirements Regulation (RLCFRR), which is embedded in the rate design of the EV DCFC stations.

At the time of the 2022 Annual Review, FBC did not have any carbon credits validated by the British Columbia Low Carbon Fuel Standard (BC-LCFS); as such, and as reflected in Table 5-1 above, FBC did not forecast any revenue from the sales of the credits for 2022 Approved. However, as of the end of the first quarter of 2022, the BC-LCFS has validated approximately 1,337 carbon credits for FBC that have accumulated since 2019, with an approximate market value of $0.625 million[21]. FBC anticipates monetizing these credits prior to the end of 2022 and has therefore reflected them in the 2022 Projected column in Table 5-1 above, and also included the $0.625 million credit in the Flow-through deferral account, to be returned to customers in 2023.

[18] Order G-215-21 dated July 14, 2021.
[19] FBC EV DCFC Service Application Decision and Order G-341-21.
[20] Includes both public charging stations owned by FBC as well as public stations owned by other entities (metered commercial accounts) as discussed in Exhibit B-6 of FBC's 2022 Annual Review, BCSEA IR1 4.3. Beginning in 2022, FBC will only be permitted to claim credits for charging stations owned by FBC. FBC does not currently claim credits for non-public EV charging services for either commercial or residential customers.
[21] 1,337 credits x $467.32 average Q1-2022 sales price (source: https://www2.gov.bc.ca/assets/gov/farming-natural-resources-and-industry/electricity-alternative-energy/transportation/renewable-low-carbon-fuels/rlcf-017.pdf).

Consistent with the practice from the 2022 Annual Review, FBC does not forecast revenue from the sale of credits that are pending validation; FBC is therefore not forecasting any of these revenues in 2023.

As part of the 2022 Annual Review Decision, FBC was directed to include the following in future Annual Review filings:[22]

> …an update on its EV DCFC charging stations' costs and revenues for the previous fiscal year along with a forecast of costs and revenues for the test period.

FBC currently has a total of 40 EV DCFC stations in service across 23 sites and is planning to install two additional DCFC stations at two of the existing sites in 2022, resulting in a total of 42 EV DCFC stations across 23 sites. Consistent with the format of the information provided during the 2022 Annual Review[23], Table 5-2 below provides the costs and revenues for 2021 Actual (previous fiscal year), 2022 Projected, and 2023 Forecast. As highlighted in Table 3-4 of Section 3.6, the RS 96 EV DCFC revenue (i.e., Line 10 of Table 5-2 below) is included as part of the Commercial Sales Revenue. Please also refer to Section 6.3.4 for a discussion of the forecast O&M expenses for the EV DCFC stations and Section 7.2.2 for a discussion of the forecast capital expenditures for the EV DCFC stations, as well as information on how the two new stations are prescribed undertakings. Once the capital expenditures are included in rate base, they impact the depreciation, amortization of CIAC, income tax and earned return related to the EV DCFC stations that are shown in Table 5-2 below.

Table 5-2: EV DCFC Stations Costs and Revenues for 2021 Actual, 2022 Projected, and 2023 Forecast ($ millions)[24]

Line	Particulars	2021 Actual	2022 Projected	2023 Forecast	Cumulative
1	Cost of Energy	0.013	0.282	0.300	
2	Less: Power Purchase Expense	(0.013)	-	-	
3	O&M	0.101	0.187	0.193	
4	Depreciation	0.307	0.456	0.612	
5	Amortization of CIAC	(0.150)	(0.191)	(0.249)	
6	Other Revenue - Carbon Credits	-	(0.625)	-	
7	Income Tax	(0.299)	(0.199)	0.158	
8	Earned Return	0.124	0.172	0.183	
9	Total Cost of Service	0.083	0.082	1.196	
10	RS 96 Revenue	(0.058)	(0.155)	(0.178)	
11	(Surplus) / Deficiency	0.025	(0.072)	1.018	0.971
12	Prior Year 2018-2020 (Surplus)/Deficiency				(0.142)
13	Cumulative (Surplus) / Deficiency				0.828

[22] FBC 2022 Annual Review Decision and Order G-374-21, p. 32.
[23] Exhibit B-3, BCUC IR1 16.1.
[24] As explained in Exhibit B-3, BCUC IR1 16.1 of the FBC 2022 Annual Review, RS 96 was approved on an interim basis in 2021 by Order G-9-18 in which the cost of energy embedded was based on BC Hydro's RS 3808; therefore,

As directed by Order G-341-21, FBC is to file a detailed assessment of the EV DCFC service by no later than December 31, 2022 or within six months of Measurement Canada's approval of DCFC energy-based metering for FBC, whichever is earlier. FBC is not expecting to receive approval from Measurement Canada prior to December 31, 2022; thus, FBC will file the detailed assessment report by December 31, 2022. As directed by the BCUC, the detailed assessment will include:

- An update of the financial models with actual and forecast information and updated assumptions;
- A detailed assessment of RS 96 and alternative rate design options;
- An overview of the current EV fast charging service market and rates across Canada and the United States;
- A proposal for a depreciation rate for its EV DCFC stations and information to support its proposal; and
- An assessment as to whether idling fees are warranted.

5.9 *OTHER RECOVERIES*

Other Recoveries are primarily comprised of fees earned on the recovery of costs for miscellaneous services, such as street light maintenance charged to municipalities and AMI radio-off meter read fees. There are no variances expected in 2022 Projected compared to 2022 Approved based on amounts recognized to date. The 2023 Forecast is expected to be slightly lower than 2022 Approved due to an expected reduction in AMI radio-off meter read fees resulting from a lower volume of customers choosing the radio-off option.

5.10 *SUMMARY*

FBC has forecast the Other Revenue components for 2023 reflecting all applicable contracts and fixed revenues, and based on the Company's best knowledge of the factors that drive the variable components. Variances in Other Revenue, with the exception of EV DCFC stations carbon credits, are shared with customers through the earnings sharing mechanism.

the cost of energy for 2021 Actual shown in Table 5-2 is equal to the power purchase expense. As approved in Order G-341-21, the permanent rate for RS 96 is based on FBC's commercial service RS 21. As such, starting in 2022, the cost of energy shown in Table 5-2 above is based on FBC's commercial service RS 21.

6. O&M EXPENSE

6.1 INTRODUCTION AND OVERVIEW

Under the MRP, FBC's O&M expense is primarily determined by formula, with the addition of a number of items that are forecast outside the formula on an annual basis.

In 2023, the formula O&M is $69.957 million, representing a 5.8 percent increase from the 2022 formula O&M, primarily due to the formula drivers. O&M expenses forecast outside the formula for 2023 are $2.323 million, representing a 26.8 percent increase from the amount approved for 2022. Overall, the 2023 Forecast gross O&M expense is $72.789 million, which is an increase of approximately 7.0 percent from the 2022 Approved level.

The components of 2023 O&M expense are shown in Table 6-1 below.

Table 6-1: 2023 O&M Expense ($ millions)

Line No.	Description	Approved 2022	Projected 2022	Forecast 2023	Reference
1	Formula O&M	$ 66.147	$ 66.147	$ 69.957	Section 11, Schedule 20, Line 8
2	Forecast O&M	1.832	1.635	2.323	Section 11, Schedule 20, Line 20
3	Prior year O&M True-up	0.053	0.053	0.509	Table 6-2, line 16
4	Total Gross O&M	68.032	67.835	72.789	Line 1 through 3
5	Capitalized Overhead	(10.177)	(10.177)	(10.918)	Section 11, Schedule 20, Line 23
6	Net O&M	$ 57.855	$ 57.658	$ 61.871	Line 4 + Line 5

In the sections below, FBC provides further details on its formula and forecast O&M expenses for 2023. Additionally, in compliance with the BCUC's directive in the MRP Decision,[25] FBC provides information related to its System Operations, Integrity and Security expenditures in Subsection 6.2.1.

6.2 FORMULA O&M EXPENSE

The formula-driven portion of O&M starts from the prior year's Approved Base O&M per Customer (UCOM), escalated by the prior year's inflation less a productivity improvement factor of 0.5 percent, and then multiplied by 75 percent of the forecast growth in average customers, resulting in the current year inflation-indexed O&M before true-up. A true-up of formula O&M based on actual average customers from two years prior is then added to the current year inflation-indexed O&M.

As calculated in Section 2, the 2023 inflation based on prior year's BC-CPI and BC-AWE, less the productivity improvement factor, is 4.017 percent.

For 2023, the annual operating and maintenance expense under the formula is calculated as:

[25] MRP Decision, p. 118.

2022 Approved formula UCOM x [1 + (I Factor – X Factor)] x [Prior Year Average Customers + (0.75 x growth in average customers)] + 2021 Formula O&M True-up

Table 6-2 below shows the calculation of the 2023 Formula O&M, including the calculation of the 2021 Formula O&M true-up. FBC notes the true-up of formula O&M is a two-year lag based on actual average customer counts from 2021.

Table 6-2: Calculation of 2023 Formula O&M ($ millions)

Line No.	Description		Forecast 2023	Reference
1	Prior Year Base Unit Cost O&M ($/ customer)	$	455	G-374-21 FBC 2022 Annual Review
2	I-Factor		4.017%	Section 2, Table 2-3, Line 11
3	Current Year Unit Cost O&M ($/customer)	$	473	
4	Average Customer Forecast		147,901	Section 2, Table 2-3, Line 13
5	2023 Inflation-Indexed O&M before 2020 True-up	$	69.957	Line 3 x Line 4 / 1,000,000
6	2021 True-up O&M		0.509	Line 16
7	Inflation-Indexed O&M	$	70.466	Line 5 + Line 6
8				
9	2021 O&M True-up			
10	2021 Actual 12 month Average Customers		144,877	FBC 2021 Annual Report
11	2021 Forecast 12 month Average Customers		143,325	G-42-21 FBC 2020-2021 Annual Review
12	Difference		1,552	Line 10 + Line 11
13	Growth Factor		75%	G-166-20 FBC MRP Decision
14	Change in Customers - True-up		1,164	Line 12 x Line 13
15	2021 Unit Costs	$	437	G-42-21 FBC 2020-2021 Annual Review
16	O&M True-up for 2023	$	0.509	Line 14 x Line 15 / 1,000,000

6.2.1 New/Incremental System Operations, Integrity and Security Funding

In the MRP Decision (page 118), the BCUC directed FBC to provide in each Annual Review a breakdown and explanation of both annual and cumulative variances between forecast/actual and formula O&M related to the approved new/incremental System Operations, Integrity and Security funding, and quantify the variances attributable to the following areas: tree management; generation dam safety; network operations apprentice program; cyber security; data analytics; and any other significant factors or miscellaneous items.

The table below shows the requested information, including the new/incremental funding in each category for 2021 Formula O&M, 2021 Actual O&M, and the resulting variances, as well as the Cumulative Forecast/Actual variance for the first two years of the MRP.

Table 6-3: System Operations, Integrity and Security New/Incremental Spending ($ millions)

Line No.	Description	2021 Formula O&M[1]	Actual 2021 O&M	2021 Forecast/Actual Variance	Cumulative Forecast/Actual Variance[2]
1	Tree Management	$ 0.080	$ 0.278	$ 0.199	$ 0.436
2	Generation Dam Safety	$ 0.246	$ 0.415	$ 0.169	$ 0.137
3	Network Operations Apprentice Program	$ 0.209	$ 0.243	$ 0.034	$ (0.167)
4	Cyber Security	$ 0.085	$ 0.085	$ -	$ 0.250
5	Data Analytics	$ 0.105	$ -	$ (0.105)	$ (0.206)
6	Other	$ -	$ -	$ -	$ -
7	Total	$ 0.724	$ 1.021	$ 0.297	$ 0.449

Notes to Table:

[1] 2021 Formula O&M is the approved 2020 formula for incremental funding with Net Inflation factor applied (3.668%).
[2] Cumulative Forecast/Actual variance is the 2020 Actual variance plus the 2021 Actual variance.

Overall, total actual spending in 2021 was $1.021 million, which is $0.297 million higher than the 2021 Formula O&M amount. Areas with notable variances include tree management, generation dam safety and data analytics.

For tree management, FBC spent $0.199 million more than the formula amount to address an increased number of unhealthy trees as part of FBC's right-of-way management program.

For generation dam safety, FBC spent $0.169 million more than the formula amount due to the continuation of dam safety review activities from 2020, as FBC required more time to complete the analysis for the determination of the dam classifications for the Upper Bonnington, Lower Bonnington and South Slocan plants.

Offsetting the higher costs in these two categories was lower spending in data analytics. FBC spent $0.105 million less than the formula amount in 2021 primarily due to labour savings from a delay in hiring. In 2021, FBC focused on finalizing the requirements for the necessary information infrastructure, with the implementation of the systems that will allow centralized data access occurring in 2022 and the addition of new data sources in priority sequence over the remaining term of the MRP.

For the first two years of the MRP, FBC spent $0.449 million more than the formula amount. Over the term of the MRP, FBC anticipates the total new/incremental spending required in the combined categories of System Operations, Integrity and Security will continue to be higher than the amount embedded in the formula. FBC will continue to manage this spending within its overall O&M spending envelope.

6.3 *O&M EXPENSE FORECAST OUTSIDE THE FORMULA*

In addition to FBC's formula O&M, FBC forecasts a number of O&M items outside of the formula annually, including pension and OPEB expense, insurance premiums, BCUC levies, and the cost

of service associated with Clean Growth initiatives, such as Electric Vehicle (EV) charging stations, as well as the O&M impacts of any exogenous factor items. For 2023, FBC has included incremental O&M for the Mandatory Reliability Standards (MRS) Assessment Report No. 13 (AR13), which was approved for exogenous treatment in the 2022 Annual Review.

The 2023 amounts are shown in Table 6-4 below along with a comparison to 2022.

Table 6-4: 2023 Forecast O&M ($ millions)

Line No.	Description	Approved 2022	Projected 2022	Forecast 2023
1	Pension/OPEB (O&M Portion)	$ (1.716)	$ (1.716)	$ (1.297)
2	Insurance Premiums	2.223	2.291	2.457
3	BCUC Levies	0.373	0.373	0.385
4	Clean Growth Initiative - EV DCFC Stations	0.187	0.187	0.193
5	Exogenous Factor - MRS	0.765	0.500	0.585
6	Total Forecast O&M	$ 1.832	$ 1.635	$ 2.323

Each of the items that is forecast outside of the formula is discussed below. Variances in pension and OPEB expense are captured in the Pension and OPEB Variance deferral account and variances in BCUC levies are captured in the BCUC Levies Variance deferral account. Variances in insurance premiums, the cost of service associated with EV charging stations, and exogenous factors are captured in the Flow-through deferral account.

6.3.1 Pension and OPEB Expense

Pension and OPEB expense for 2023 is based upon actuarial estimates using a range of assumptions as of December 31, 2021 with an update of discount rate estimates as of April 30, 2022 provided by the Company's external third party actuary, Willis Towers Watson. The discount rate determined reflects the market yields of high quality Canadian corporate bonds which have increased since 2021. In addition to O&M, pension and OPEB expense is embedded in Capital Expenditures, as shown in Table 6-5.

Table 6-5: Pension and OPEB Expense ($ millions)

Line No.	Description	Approved 2022	Projected 2022	Forecast 2023
1	O&M	$ (1.716)	$ (1.716)	$ (1.297)
2	Capital (Approved)	3.807	3.807	1.888
3	Capital (to Pension & OPEB Variance Deferral)[1]	(0.400)	(0.400)	-
4	Total	$ 1.691	$ 1.691	$ 0.591

Notes to Table:

[1] This line item represents the pension and OPEB expense difference between the estimates embedded in the Regular Capital Expenditure forecasts on Line 2 in this table, which were based on the pension and OPEB actuarial estimates provided in 2019 as part of the 2020 to 2024 MRP Application, and the actuarial estimates

updated for 2023 rate-setting purposes. There is no difference for 2023 since FBC was directed to file an updated forecast of the 2023 and 2024 Regular Capital Expenditures in the 2023 Annual Review, as directed in the MRP Decision and Order G-166-20.

The variance between the 2022 Approved and actual pension and OPEB expense, including the known capital variance on Line 3 of Table 6-5 above, and any variance between the 2023 Forecast and actual amounts, is flowed through to the Pension and OPEB Variance deferral account and amortized into rates over a three-year period, as approved by Order G-139-14.

The 2023 Forecast pension and OPEB expense has decreased by $1.100 million compared to the 2022 Approved expense primarily due to the following factors, which are all components of pension and OPEB expense:

- An approximate $3 million decrease in current service costs due to an increase in the discount rate. The discount rate, which is determined with reference to the market rate of interest on high quality debt instruments at a point in time, increased from 3.5 percent, which was used to determine the 2022 Approved expense, to 4.5 percent, which is used to determine the 2023 Forecast expense;

offset in part by:

- An approximate $2 million increase in interest costs due to an increase in the discount rate.

6.3.2 Insurance Premiums

The component of insurance expense tracked outside of formula O&M relates to the insurance premium expense allocated to FBC by Fortis Inc. as set out in Table 6-6 below.

Table 6-6: Insurance Premiums ($ millions)

Line No.	Description	Approved 2022	Projected 2022	Forecast 2023	Reference
1	Insurance Premiums	$ 2.223	$ 2.291	$ 2.457	Section 11, Schedule 20, Line 16
2	Total	$ 2.223	$ 2.291	$ 2.457	

The 2022 Projected insurance premium expense of $2.291 million is $0.068 million higher than 2022 Approved, as it incorporates FBC's actual July 2022 to June 2023 insurance renewals of $2.253 million. The higher premiums experienced in 2022 are expected to continue into 2023, though at a lower rate of increase. The 2023 Forecast is $2.457 million, which is an increase of $0.166 million from 2022 Projected. The 2023 Forecast is calculated as the amount of the first six months of actual annual insurance premiums for January to June 2023 of $1.126 million and

applying a 5 percent increase for the remaining six months, plus the cost of fire fighting services FBC pays to the Province of $0.148 million.[26]

6.3.3 BCUC Levies

FBC's 2023 Forecast for BCUC levies is $0.385 million. The 2023 Forecast is based on Order G-188-22 for the BCUC's Fiscal 2022/23 year, which represents the best information available at this time, as the BCUC levy calculation for Fiscal 2023/24 will not be available until early or mid 2023.

BCUC levies receive flow-through treatment, with annual variances between actual and forecast amounts in O&M expense being recorded in the BCUC Levies Forecast Variance deferral account and amortized over one year.

6.3.4 Clean Growth Initiative – Electric Vehicle (EV) DCFC Stations

As discussed in Section 5.8, FBC's EV DCFC stations are prescribed undertakings under section 5 of the GGRR[27] and the cost of service associated with EV DCFC stations is subject to flow-through treatment. Please refer to Table 5-2 in Section 5.8 which provides a summary of the EV DCFC stations' costs and revenues from 2021 Actual to 2023 Forecast.

As shown in Table 6-7 below, the 2022 Projected EV DCFC station O&M expense is expected to be consistent with 2022 Approved[28], and consists of network management, repairs and maintenance, inspection fees and FBC labour costs. The 2023 Forecast EV DCFC station O&M expense is anticipated to be similar to the 2022 Projected level, with an approximate increase of $6 thousand primarily due to inflation.

Table 6-7: Clean Growth Initiative – EV DCFC Stations ($ millions)

Line No.	Description	Approved 2022	Projected 2022	Forecast 2023	Reference
1	Clean Growth Initiative - EV DCFC	$ 0.187	$ 0.187	$ 0.193	Section 11, Schedule 20, Line 19
2	Total	$ 0.187	$ 0.187	$ 0.193	

6.3.5 MRS Incremental Operating Expenses

In the 2022 Annual Review Decision,[29] FBC received approval of exogenous factor treatment for the incremental O&M and capital costs associated with MRS AR13. As explained in the 2022

[26] $2.253 million/2 = $1.126 million. $1.126 million x 1.05 = $1.183 million. $1.126 million + $1.183 million + $0.148 million annual firefighting service fee = $2.457 million.
[27] Order G-215-21 dated July 14, 2021.
[28] Consistent with the 2022 Annual Review Decision, FBC included the 2022 forecast revenues and expenses associated with the EV DCFC stations in the Compliance Filing to the Annual Review Decision and Order G-374-21 because approval of the EV DCFC Service Application was not received until November 24, 2021. Accordingly, the 2022 Approved amount reflected in Table 6-7 is the amount included in the Compliance Filing.
[29] Decision and Order G-374-21, p. 21.

Annual Review, FBC expected to incur one-time costs in 2021 and 2022 related to the adoption of the standards in AR13 as well as ongoing incremental O&M expenses commencing in 2023[30].

BC Hydro issued AR13 on May 1, 2020 recommending adoption of seven standards, retirement of one standard, and holding one standard in abeyance pending resolution of the Planning Coordinator (PC) function along with the NERC Glossary dated August 12, 2019. The BCUC issued Order R-19-20 on September 8, 2020 accepting BC Hydro's recommendation and determined the effective dates of those standards. Of the standards and respective NERC Glossary terms assessed by FBC, five standards have associated costs, of which one was held in abeyance. The effective date for the four adopted standards is April 1, 2023, including the existing CIP-005-6 (Electronic Security Perimeter(s)), CIP-008-6 (Incident Reporting and Response Planning) and CIP-010-3 (Configuration Change Management and Vulnerability Assessments) standards and the new CIP-013-1 (Supply Chain Risk Management) standard. In order to address these changes, FBC is required to monitor and disconnect vendor remote access, evaluate and report attempts to compromise, ensure software downloads and installations are unaltered and secure, and assess risk for any product or service procured for Bulk Electrical System assets under the Critical Infrastructure and Protection (CIP) standards. These requirements are reflected in the 2022 Approved, 2022 Projected, and 2023 Forecast expenses in Table 6-8 below.

The following table provides the 2022 Approved and Projected and the 2023 Forecast of incremental O&M related to MRS AR13.

Table 6-8: Incremental O&M for MRS AR13 ($ millions)

Line No.	Description	Approved 2022	Projected 2022	Forecast 2023	Reference
1	Labour	$ 0.335	$ 0.200	$ 0.490	
2	Non-Labour	0.280	0.250	0.095	
3	Contingency	0.150	0.050	-	
4	Total	$ 0.765	$ 0.500	$ 0.585	Section 11, Schedule 20, Line 18

The 2022 Projected O&M expense is lower than 2022 Approved by $0.265 million. The reduction of $0.265 million is a result of less overall effort required to modify existing programs and processes as mentioned above than originally expected.

The 2023 Forecast O&M expense of $0.585 million is related to the expected ongoing efforts to maintain procedures and processes, hardware and software that address supply chain risk assessments, ongoing licensing and maintenance of the hardware and software, and the documentation to maintain compliance of AR13. The 2023 Forecast is based on the expected costs in 2022 Projected and is therefore less than the 2022 Approved level. These costs are annual and will continue in future years.

[30] Exhibit B-2, Annual Review for 2022 Rates Application, Section 12.2.1, pp. 103-104; Exhibit B-3, BCUC IR1 24.2.

6.4 NET O&M EXPENSE

Net O&M expense is gross O&M less capitalized overhead. As approved by the BCUC in Order G-166-20, the capitalized overhead rate is set at 15 percent for FBC, unchanged from 2022. After capitalized overhead, the net O&M expense is $61.871 million in 2023.

6.5 SUMMARY

Overall, the increase in gross O&M expense from 2022 Approved to 2023 Forecast is 7.0 percent. Formula-driven O&M is increasing at a rate of 5.8 percent, and O&M forecast outside the formula is 26.8 percent higher than 2022 Approved.

The capitalized overhead rate for 2023 remains unchanged from 2022.

7. RATE BASE

7.1 INTRODUCTION AND OVERVIEW

FBC forecasts its Rate Base to be $1.675 billion for 2023. Rate Base is comprised of mid-year net plant in service, work in progress not attracting AFUDC, unamortized deferred charges, working capital, and the utility plant acquisition adjustment.[31]

FBC's 2023 Rate Base includes the full-year impacts of the 2022 closing projected plant balances as well as the impact of the following amounts:

- Mid-year impact of regular capital additions, net of CIAC additions, of $94.209 million;
- Mid-year impact of plant depreciation, net of CIAC amortization, of $64.407 million; and
- Capital additions of CPCNs and other Major Projects totalling $45.439 million[32], as discussed in Section 7.3 below, which include:
  - Full-year impact of $21.250 million for the capital expenditures and related AFUDC for the Kelowna Bulk Transformer Additions (KBTA) Project, which is expected to complete in late 2022 or early 2023;
  - Full-year impact of $16.151 million for the final capital expenditures and related AFUDC for the Corra Linn Dam Spillway Gates Replacement Project, which is expected to complete in 2022; and
  - Full-year impact of $8.036 million for the final capital expenditures and related AFUDC for the Playmor Substation Upgrade Project, which is expected to complete in 2022.

In addition, various changes in deferred charges, working capital and other items increase rate base by a net amount of $24.303 million in 2023.

Details of the 2023 Forecast plant balances can be found in Section 11, Schedules 5 through 9.

7.2 REGULAR CAPITAL EXPENDITURES

As part of the MRP Decision and Order G-166-20, FBC received the following approvals for capital expenditures:

- Approval of FBC's forecasts submitted for regular capital expenditures for the years 2020 through 2022; and

[31] The utility plant acquisition adjustment relates to the 1982 purchase of Plants 2, 3, and 4 and is being amortized over a period of 64 years.

[32] The 2023 capital additions of $45.439 million also include $0.002 million for the close out costs and related AFUDC in 2022 for the UBO Old Units Refurbishment Project.

- Approval of a number of items to be forecast on an annual basis.

Further, in the MRP Decision the BCUC directed FBC to file an updated forecast of the 2023 and 2024 regular capital expenditures in the 2023 Annual Review.[33]

The components of FBC's 2023 regular capital expenditures are shown in Table 7-1 below.

Table 7-1: Regular Capital Expenditures ($ millions)

Line No.	Description	Approved 2022	Projected 2022	Forecast 2023	Reference
1	Forecast Capital	$ 81.925	$ 87.735	$ 94.428	Table 7-2 and Table 7-3, Line 4
2	Flow-Through Capital	0.935	2.430	0.248	Table 7-11, Line 3
3	Total Gross Regular Capital	$ 82.860	$ 90.165	$ 94.676	Sum of Lines 1 & 2
4	Less CIAC	(11.712)	(8.287)	(11.628)	Section 11, Schedule 9, Line 2
5	Net Regular Capital	$ 71.148	$ 81.878	$ 83.048	Sum of Lines 3 & 4

In Section 7.2.1, FBC provides its updated 2023 and 2024 regular capital forecasts. In Section 7.2.2, FBC provides details on its forecast flow-through expenditures for 2023, consistent with the format provided in previous annual reviews during this MRP term.

7.2.1 Updated 2023 and 2024 Forecast Regular Capital Expenditures

As stated above, in the MRP Decision and Order G-166-20[34], the BCUC directed FBC to file updated 2023 and 2024 regular capital forecasts as part of the 2023 Annual Review. The BCUC in its decision highlighted FBC's evolving operating environment and inherent uncertainties in the capital forecasts, and thus considered it appropriate for FBC to have the opportunity to true-up its capital spending and re-forecast its capital for the final two years of the MRP term. Specifically, the BCUC stated the following:

> …FEI and FBC face evolving operating environments and there are inherent uncertainties in the five-year forecast. Reviewing the capital forecast in 2022 allows for a review of any significant variances between forecast and actual to date and provides an opportunity to true-up the rate-base for actual spending and to re-forecast the remaining years in the MRP term.[35]

As further explained below, FBC has begun to experience pressures due to a variety of factors which are outside of the Company's control and could not have been anticipated at the time of the MRP proceeding, including supply chain issues and rising commodity prices and other inflationary pressures brought on by the COVID-19 pandemic and the war in Ukraine. These factors, as well as the increased cost and complexity in permitting and land acquisition as well as increased growth, are impacting FBC's ability to execute on all of its planned capital projects and programs. While FBC has pursued various mitigation measures to manage through the spending

[33] MRP Decision and Order G-166-20, p. 131.
[34] Directive 1.c. of Order G-166-20.
[35] MRP Decision and Order G-165-20, p. 131.

pressures, FBC requires an increase in its capital spending for 2023 and 2024 compared to its original forecasts to execute on its planned activities.

The following tables summarize the growth, sustainment and other capital expenditures[36]. The first table presents the 2020 through 2022 Approved forecasts (i.e., the forecasts approved in the MRP Decision) and the 2023 and 2024 forecasts which were reviewed during the MRP proceeding (Original Forecasts). The second table provides the Actual/Projected results for 2020 through 2022 and FBC's updated forecasts for 2023 and 2024 (Updated Forecasts).

Table 7-2: Regular Capital Expenditures, 2020-2022 Approved and 2023-2024 Original Forecasts ($ millions)

Line No.	Description	Approved 2020	Approved 2021	Approved 2022	Original Forecast 2023	Original Forecast 2024
1	Growth Capital	27.029	23.042	24.339	26.283	23.170
2	Sustainment Capital	50.463	49.818	42.830	44.377	53.470
3	Other Capital	15.752	14.712	14.756	15.281	15.134
4	Total	93.244	87.573	81.925	85.941	91.774

Table 7-3: Regular Capital Expenditures, 2020-2021 Actual, 2022 Projected and 2023-2024 Updated Forecasts ($ millions)

Line No.	Description	Actual 2020	Actual 2021	Projected 2022	Updated Forecast 2023	Updated Forecast 2024
1	Growth Capital	28.799	21.865	29.868	30.973	24.568
2	Sustainment Capital	47.325	49.601	41.486	45.797	58.673
3	Other Capital	16.036	15.349	16.381	17.658	17.213
4	Total	92.160	86.815	87.735	94.428	100.454

In Section 7.2.1.1, FBC describes its updated forecasts for growth and sustainment capital. In Section 7.2.1.2, FBC describes its updated forecasts for other capital.

7.2.1.1 Growth and Sustainment Capital

7.2.1.1.1 GROWTH CAPITAL

Growth capital expenditures involve transmission and distribution system improvements required to meet incremental customer and load growth, in addition to the cost of connecting new customers to the system.

The three main growth capital portfolios are: (i) Transmission Growth; (ii) Distribution Growth; and (iii) New Connects. In the MRP Application, FBC provided forecasts of these three categories of

[36] Excluding sustainment CIAC.

growth capital expenditures based on a bottom-up approach which included a two percent inflationary increase per year.

The following tables provide the 2020 to 2022 Approved vs Actual/Projected expenditures and the Original and Updated 2023 and 2024 Forecasts.

Table 7-4: Growth Capital Expenditures 2020-2022 ($ millions)

Line No.	Description	2020 Approved	2020 Actual	2021 Approved	2021 Actual	2022 Approved	2022 Projected
1	Transmission Growth	5.172	7.109	2.063	0.744	2.740	5.524
2	Distribution Growth	3.716	1.926	1.876	1.965	1.807	3.450
3	New Connects	18.141	19.764	19.104	19.156	19.792	20.894
4	Total Growth Capital	27.029	28.799	23.042	21.865	24.339	29.868

Table 7-5: Growth Capital Expenditures 2023 and 2024 ($ millions)

Line No.	Description	2023 Original Forecast	2023 Updated Forecast	2024 Original Forecast	2024 Updated Forecast
1	Transmission Growth	5.195	6.223	1.086	1.088
2	Distribution Growth	1.899	2.800	1.921	1.716
3	New Connects	19.188	21.951	20.163	21.764
4	Total Growth Capital	26.283	30.973	23.170	24.568

As shown in Table 7-5 above, FBC's Updated Forecasts for growth capital have increased by $4.690 million in 2023 and $1.398 million in 2024 compared to the Original Forecasts. FBC is forecasting increases in all three growth capital portfolios in 2023. For 2024, the increase is primarily in the New Connects portfolio, with FBC reducing the expenditures for the Distribution Growth portfolio to offset some of the required increases. These increases are described in Section 7.2.1.1.3 below.

7.2.1.1.2 SUSTAINMENT CAPITAL

The expenditures within sustainment capital include system improvements to the transmission and distribution system in order to maintain existing equipment to meet forecast load and for the safety, reliability and quality of the system. FBC operates and maintains four generating facilities with a total of 15 units. FBC regularly monitors its infrastructure to ensure it meets industry standards and guidelines, complies with regulations, and operates safely to minimize risk to the public and employees. FBC also identifies and addresses hazards and risks that require immediate attention through specific projects. FBC's telecommunications system is an integral component in the protection relaying system, remedial action schemes, substation operations and control, and generation dispatch systems. The system requires ongoing investment to replace aging or failed systems for safe and reliable operation of the system and to ensure business needs continue to be met.

The five main sustainment capital portfolios are: (i) Generation; (ii) Transmission Sustainment; (iii) Stations Sustainment; (iv) Distribution Sustainment; and (v) Telecommunications. In the MRP

Application, FBC provided forecasts of these five categories of sustainment capital expenditures based on a bottom-up approach which included a two percent inflationary increase per year.

The following tables provide the 2020 to 2022 Approved vs Actual/Projected expenditures and the Original and Updated 2023 and 2024 Forecasts.

Table 7-6: Sustainment Capital Expenditures 2020-2022 ($ millions)

Line No.	Description	2020 Approved	2020 Actual	2021 Approved	2021 Actual	2022 Approved	2022 Projected
1	Generation	6.697	5.884	6.766	6.949	6.309	6.731
2	Transmission Sustainment	8.353	12.506	6.387	10.667	5.698	7.841
3	Stations Sustainment	13.538	4.821	13.624	12.083	5.279	6.889
4	Distribution Sustainment	20.057	21.530	20.058	17.479	19.262	17.439
5	Telecommunications	1.818	2.584	2.983	2.423	6.280	2.587
6	Total Sustainment Capital	50.463	47.325	49.818	49.601	42.830	41.486

Table 7-7: Sustainment Capital Expenditures 2023 and 2024 ($ millions)

Line No.	Description	2023 Original Forecast	2023 Updated Forecast	2024 Original Forecast	2024 Updated Forecast
1	Generation	7.008	7.623	6.514	7.225
2	Transmission Sustainment	7.951	9.159	7.591	12.800
3	Stations Sustainment	3.793	7.928	15.971	15.229
4	Distribution Sustainment	19.710	17.480	19.922	18.219
5	Telecommunications	5.915	3.606	3.472	5.199
6	Total Sustainment Capital	44.377	45.797	53.470	58.673

As shown in Table 7-7 above, FBC's Updated Forecasts for sustainment capital have increased by $1.420 million in 2023 and $5.203 million in 2024 compared to the Original Forecasts. For 2023, the increases are primarily in the Transmission Sustainment and the Stations Sustainment portfolios, with FBC proposing to reduce the expenditures for the Distribution Sustainment and the Telecommunications portfolios to offset some of the required increases. For 2024, the increases are primarily in the Transmission Sustainment and Telecommunications portfolios, with FBC proposing to reduce the expenditures for the Distribution Sustainment and the Stations Sustainment portfolios to offset some of the required increases. These increases are described in Section 7.2.1.1.3 below.

7.2.1.1.3 DRIVERS OF UPDATED GROWTH AND SUSTAINMENT CAPITAL FORECASTS

The drivers of the increases in growth and sustainment capital are summarized as follows:

- Significant inflationary increases brought on by unanticipated events such as the COVID-19 pandemic and the war in Ukraine, which have resulted in large cost escalations in materials, labour and fuel;
- Increases in growth capital as a result of more customer applications; and
- Additional reliability, refurbishment or end of life projects being required that were not anticipated at the time of the MRP proceeding.

These cost drivers, as well as the mitigation efforts FBC has undertaken during the first three years of the MRP term, are described in the following subsections.

FBC is Experiencing Significant Inflationary Pressures

FBC's Original Forecasts were developed using an assumption of two percent for annual inflation. While FBC has generally managed its overall capital spending within the approved levels over the first two years of the MRP term, FBC has begun to experience pressures throughout its growth and sustainment portfolios. These pressures coincide with the significant global market events experienced during this time period, including the COVID-19 pandemic, supply chain disruptions, and the war in Ukraine. These unforeseen events have had a significant impact on market conditions for many commodities and services that make up FBC's supply chain, and the impacts are still being felt and continue to contribute to volatility in the supply chain and the overall commodity and services market in 2022.

In order to better understand the extent of the inflationary impacts that have affected North American utilities since 2020 and to compare the impacts on the industry with FBC's experience, FBC engaged Wood Mackenzie Supply Chain Consulting (Wood Mackenzie) to provide a market report on electric and gas utility transmission and distribution (T&D) markets from 2020 to 2022 and the anticipated impact until the end of 2024 (Wood Mackenzie Report). Wood Mackenzie identified an average escalation of 17.5 percent in capital costs for electric utilities between the period of the first quarter of 2020 and the first quarter of 2022. The Wood Mackenzie Report is based on the aggregated spend from utilities across North America, and incorporated over 150 indices which roll up to form the model for each category. Indices specific to BC have also been incorporated where appropriate, particularly around trades and other labour in the Province. This report has been included as Appendix C1.

FBC has experienced significant inflationary pressures during the first three years of the MRP term and expects these pressures will continue into 2023 and 2024. In particular, FBC has experienced the most significant inflationary cost pressures for poles, transformers and wires/cables. The projects in Transmission, Distribution and Station growth and sustainment portfolios have been impacted by incremental increases in the cost of these materials since 2020. Cost escalation is also impacting FBC due to steel commodity prices in North America, which have increased approximately 117 percent from the first quarter of 2020.

As shown in the Wood Mackenzie Report, it is expected that the average capital costs for electric utilities will continue to rise until the fourth quarter of 2024, although at a slower pace than what was experienced between the first quarter of 2020 and the first quarter of 2022, and will not come back down to the 2020 level. This expectation also aligns with the Bank of Canada's July 2022 Monetary Policy Report[37] which projects that CPI is expected to hover around 8 percent in the third quarter of 2022 before decreasing to approximately 3 percent by the fourth quarter of 2023 and 2 percent in 2024.

[37] https://www.bankofcanada.ca/wp-content/uploads/2022/07/mpr-2022-07-13.pdf.

Updated Forecasts Reflect Increased Growth

The New Connects category includes the installation of new electric services consisting of additions to FBC overhead and underground distribution facilities. These capital expenditures allow FBC to meet its obligation to provide reliable service to customers in its service area. This category also funds any costs associated with upgrading FBC facilities to provide service for an extension or drop service. Consistent with past practice, the forecast expenditures for New Connects are based on a historical rolling average of expenditures adjusted by inflation. The overall increase is due to more customer applications for connections.

Updated Forecasts Reflect New Growth and Sustainment Projects

As noted by the BCUC in the MRP Decision, there are inherent uncertainties in capital forecasting, particularly when forecasting projects over a five-year period. In the MRP Application, FBC identified projects over $1 million that it anticipated undertaking over the five-year MRP term. Due to a variety of reasons, such as land and permitting issues, re-prioritization of capital spending, and changes in capacity requirements, some projects have been delayed or cancelled while other new projects have been identified and prioritized.

For example, in order to address aging infrastructure and to support load growth while maintaining current levels of reliability, substation rebuild projects or transformer addition projects are required. In some cases, these projects require increasing the station footprint and acquiring more adjacent land or larger parcels of land in new locations. The selection of an appropriate land parcel can be a lengthy process that can include activities such as open houses as part of stakeholder consultation. Given the uncertainties related to consultation and purchase negotiation, it introduces risk to project timelines if these activities are not completed in advance of the project execution window. The need to acquire land has arisen in a number of FBC's planned projects and has resulted in increased costs and, at times, delays to the project schedule. Projects that have been impacted by land acquisition requirements are described in Appendix C2 and include, as an example, the Fruitvale Station Upgrade project.

As detailed in the MRP Application[38], FBC actively manages its capital plan to ensure projects are planned and executed efficiently. Accordingly, the timing, scope, and cost of the individual projects and programs within the overall regular capital forecasts are subject to change, and FBC may identify new projects and programs that need to be added over the term of the MRP. The capital plan contains a mix of projects across the portfolio categories, some of which are time sensitive and others that have some schedule flexibility. The plan is developed with the understanding that conditions change and the plan must be capable of adapting. This provides FBC flexibility to manage and execute normal levels of unforeseen urgent work that are expected to occur throughout the year within the resource and budget constraints of the capital plan. While this flexibility means that individual projects may move around, at a portfolio level, FBC has consistently executed a similar portfolio of work to the Original Forecasts.

[38] Section 3.4.1.5, page C-106.

In Appendix C2, FBC provides a list of the projects over $1 million which are included in the Updated Forecasts for 2023 and 2024.

FBC Employed Mitigation Strategies to Limit Cost Pressures

FBC has implemented the following strategies to mitigate the impact of the aforementioned cost pressures:

- Re-scheduling projects that can be safely re-scheduled to 2023 to accommodate other project costs increase that could not be deferred. As detailed in Section 3.2 (Capital Planning Process – page C-52) of the MRP Application, FBC manages its capital investment plan to maintain a safe and reliable system, optimize resources and spending, and achieve efficiencies and cost savings. The capital plan contains a mix of projects, some of which are time-sensitive and others that have some schedule flexibility. The plan is developed with the understanding that conditions change, and the plan must be capable of adapting. This provides FBC flexibility to manage and execute normal levels of unforeseen urgent work that is expected to occur throughout the year within the resource and budget constraints of the capital plan. While FBC has delayed some work with flexible timing to accommodate the increased demands in 2022, this has only mitigated part of the capital pressures due to the magnitude of market pressures;
- Entering into long-term supply contracts for many commonly used materials and service providers (e.g., engineering consultants, construction contractors, etc.);
- Competitively tendering large contracts for materials and services to ensure competitive pricing;
- Communicating with critical suppliers and contractors to discuss issues and mitigation strategies;
- Negotiating collective agreement with unionized FBC employees that provide longer-term stability for internal labour rates (IBEW and MoveUP agreement expires in 2023); and
- Optimally allocating construction work to internal or external construction crews as appropriate.

Despite the mitigation strategies listed above, FBC has not been able to fully mitigate cost increases due to the cost drivers described above.

7.2.1.2 Other Capital

In this section, FBC provides its Updated Forecasts for other capital. Other capital includes Equipment, Facilities and Information System (IS) expenditures.

Table 7-8 below shows the Approved and Actual/Projected other capital from 2020 to 2022 while Table 7-9 below shows the Original and Updated Forecasts of other capital for 2023 and 2024. FBC notes that the majority of the increase shown in the Updated Forecasts is related to Facilities, primarily as a result of the Kelowna Space Project.

Table 7-8: Approved and Actual/Projected Other Capital Expenditures 2020-2022 ($ millions)

Line No.	Description	2020 Approved	2020 Actual	2021 Approved	2021 Actual	2022 Approved	2022 Projected
1	Equipment	3.407	3.444	3.338	2.711	3.274	3.560
2	Facilities	3.264	3.434	2.346	3.685	2.346	2.846
3	Information Systems	9.081	9.158	9.028	8.953	9.136	9.975
4	Total Other Capital	15.752	16.036	14.712	15.349	14.756	16.381

Table 7-9: Original and Updated Forecasts of Other Capital Expenditures 2023 and 2024 ($ millions)

Line No.	Description	2023 Original Forecast	2023 Updated Forecast	2024 Original Forecast	2024 Updated Forecast
1	Equipment	3.681	4.099	3.388	3.717
2	Facilities	2.346	4.305	2.346	4.096
3	Information Systems	9.254	9.254	9.400	9.400
4	Total Other Capital	15.281	17.658	15.134	17.213

The following sections provide further details on the Updated Forecasts for other capital.

7.2.1.2.1 EQUIPMENT CAPITAL

Equipment capital expenditures include the acquisition of vehicles, specialized tools and equipment. Expenditures for the equipment listed above are driven by obsolescence, excessive wear and regulatory compliance.

FBC's 2023 and 2024 capital forecasts for Equipment have increased by $0.418 million and $0.329 million, respectively, compared to the Original Forecasts. The average unit cost per vehicle has risen significantly as supply of vehicles has reduced in relation to demand in the marketplace. In particular, FBC is experiencing the following changes to the average cost of the vehicles:

- Substantial reduction in volume-based concessions from manufacturers to all commercial fleet (from $10.5 thousand to $2.5 thousand per unit);
- Increased costs on steel, aluminum, glass and paint; and
- Inflationary surcharges on transport of materials, services and labour by manufacturers;

7.2.1.2.2 FACILITIES CAPITAL

Facilities capital expenditures include the acquisition or leasing of land, buildings, and building equipment. Facilities capital expenditures focus primarily on capacity planning, upgrading and replacement of end of life assets. The Facilities department ensures approved facilities projects are built to meet internal standards, building codes and regulations, and provide a long-term solution toward meeting the business requirements.

As shown in Table 7-9 above, FBC's 2023 and 2024 Facilities capital forecasts have increased by $1.959 million and $1.750 million in 2023 and 2024, respectively, compared to the Original

Forecasts. As further explained below, the majority of the increase is for the Kelowna Space Project. The remainder of the increase is related to: (i) energy management and GHG emissions reductions activities that FBC is planning to undertake to improve the adaptability and resiliency of FBC's facilities; and (ii) the installation of EV infrastructure at FBC's facilities.

Kelowna Space Project

FBC continues to experience capacity challenges at numerous locations for office, material storage and parking spaces and has been working to address these complex challenges. These capacity issues are impacting FBC's facilities across the Province and require different solutions depending on the location, as the challenges vary depending on the unique circumstances of each region. At the time of filing the MRP Application, FBC was in the process of developing a strategy for a cost-effective solution to the capacity issues in the Kelowna area, and therefore did not include this project in its Original Forecasts.

Both FEI and FBC have been experiencing space capacity challenges in the Kelowna region. Identifying solutions to address the space constraints has been very challenging, particularly due to the significant escalation in real estate costs to acquire new industrial land in the Kelowna area. However, the companies have now finalized a solution which leverages the use of FEI's and FBC's existing sites and results in the leasing of a new site for FEI's and FBC's Shared Services Departments. As further explained below, the Kelowna Space Project is a combined project for FEI and FBC, and the cost of the project has therefore been allocated between the two utilities accordingly. The total cost of the Kelowna Space Project is $13.930 million. Of this total, approximately $2.934 million is allocated to FBC based on employee count, with $1.209 million and $1.000 million reflected in FBC's Updated Forecasts for 2023 and 2024, respectively[39].

As part of the Kelowna Space Project, both FEI and FBC Shared Services Departments (Support Services) located in Kelowna will relocate to a new office lease facility approximately 25,000 ft^2 in size. Tenant improvements will be completed in 2023 and the Shared Services Departments will be relocated to this new leased facility. The allocation of leasing costs for this site will be determined using a cost driver approach based on the number of employees for FEI and FBC. In addition, FBC's Electrical Operations will move to the existing FEI-owned Springfield facility, as that location has a larger footprint and thus better aligns with the required Electrical Operations Space Program. FEI's Gas Operations will move to the existing FBC-owned Benvoulin property, as Gas Operations has a smaller footprint requirement. Broadly speaking, the Electrical and Gas Operations will "swap" locations.

Each building will require modifications to accommodate the Space Program requirements. Work will commence in late 2023 to complete the swap in 2025. Changes in building occupancy will be captured through new lease agreements where FEI will lease the entire Benvoulin building from

[39] There was also approximately $0.631 million and $0.094 million of actual costs related to the Kelowna Space Project allocated to FBC in 2020 and 2021, respectively, with the total allocation to FBC equaling approximately $2.934 million, including the forecast expenditures in 2023 and 2024.

FBC and FBC will lease the entire Springfield building from FEI. The buildings will remain operational while these changes are made.

The Kelowna Space Project results in a number of benefits for both FEI and FBC, including:

- Provision of sufficient space for both Operations and Support Services:
  - Support Services space requirement of 25,000 ft^2 of office at a new leased facility;
  - Gas Operations space requirement of 15,000 ft^2 of office and 12,000 ft^2 of industrial storage and shop space align with the sizing of the Benvoulin buildings and site; and
  - Electric Operations space requirement of 33,000 ft^2 of office and 13,000 ft^2 of industrial storage and shop space align with the sizing of the Springfield buildings and site;
- Retaining and updating the existing properties and adding a leased office facility results in a reasonable implementation timeline; changes are made at a measured pace to minimize business and employee disruption and do not require temporary relocation to another facility;
- The solution ensures Electric Operations remain located in an area that best supports their service territory; by not relocating this group farther from the city, potential inefficiencies are prevented;
- The solution is cost effective in contrast to other options such as purchasing new property or constructing a new Operation Hub, and utilizes FEI's and FBC's existing properties to the best extent possible; and
- Each Operations group is located in its own facility, increasing planning, operations, and management efficiencies.

Capital Expenditures to Support Energy Efficiency and GHG Reductions

The Updated 2023 and 2024 Forecasts include $0.750 million in each year for expenditures that are specifically in support of energy efficiency and GHG emissions reductions. These expenditures consist of projects that will result in reduced electrical and natural gas usage in FBC's facilities and/or will result in GHG emissions reductions. Where applicable, the planned projects are aligned with the ISO 50,001 Energy Management Standard, and enable FBC to prepare for the impacts of climate change and the transition to net-zero emissions. These planned projects will improve FBC's buildings' energy efficiency, support the adoption of electric vehicles, and contribute to efforts towards climate change and the Province's CleanBC Plan targets.

FBC is pursuing energy management and GHG emissions reduction opportunities for its buildings as part of the Company's climate action initiatives, including energy management activities related to climate adaptation, mitigation, and resiliency for buildings. FBC also plans to install EV charging infrastructure at FBC's facilities for fleet use.

Historically, the Facilities department has prioritized capital spending for capacity planning, end-of-life replacements, and meeting building codes and regulations. However, in light of the importance of addressing climate change, Facilities is now focusing on advancing climate action initiatives and strategies. Examples of advancements are installation of EV charging infrastructure, upgrading lighting to LED, completing energy audits to identify opportunities to inform capital planning, and incorporating energy efficiency components in long-term lease agreements.

7.2.1.2.3 INFORMATION SYSTEMS

FBC's Information Systems (IS) expenditures focus on enhancing, replacing, upgrading and sustaining existing applications and infrastructure or, as needed, introducing new technology capabilities in order to improve safety, customer service, reliability and efficiency.

As shown in Table 7-8 above, the actual/projected expenditures for 2020 through 2022 are generally consistent with what was forecast in the MRP Application. As such, FBC has not made any changes to the 2023 and 2024 IS capital forecasts (Table 7-9 above) compared to what was presented in the MRP Application as there have been no changes in circumstances or anticipated spending that would warrant revisions.

7.2.1.3 Summary of FBC's Updated Regular Capital for 2023 and 2024

FBC provided an updated forecast for regular growth, sustainment and other capital in 2023 and 2024. These Updated Forecasts are summarized in Table 7-10 below.

Table 7-10: Summary of 2023-2024 Updated Forecasts of Regular Capital

Line No.	Description	2023 Updated Forecast	2024 Updated Forecast
1	Growth Capital	30.973	24.568
2	Sustainment Capital	45.797	58.673
3	Other Capital	17.658	17.213
4	Total Regular Capital	94.428	100.454

For FBC's growth and sustainment capital, the Updated Forecasts reflect the significant and unanticipated cost pressures experienced over recent years. These pressures, generally experienced by North American utilities, are being driven by factors outside of FBC's control, and include, among others, the COVID-19 pandemic, supply chain pressures and the war in Ukraine, as well as growth-related expenditures and necessary reliability, refurbishment and end of life replacement projects. The Updated Forecasts will ensure FBC's ability to execute its planned growth and sustainment capital programs which are critical to ensuring the ongoing safe and reliable operation of FBC's system and ensuring that FBC is able to meet its customer's needs.

For FBC's other capital, the Updated Forecasts are primarily related to the Kelowna Space Project, as well as expenditures for activities at FBC's facilities related to energy efficiency and GHG emissions reductions.

7.2.2 Flow-Through Capital Expenditures

FBC is afforded flow-through treatment for certain capital items due to a variety of factors, including their uncontrollable nature, because they drive incremental revenues, because they are related to Clean Growth initiatives, or because of the uncertainty in scope, costs and timing. The amounts for 2023 are shown in Table 7-11 below along with a comparison to 2022.

Table 7-11: Flow-Through Regular Capital Expenditures ($ millions)

Line No.	Description	Approved 2022	Projected 2022	Forecast 2023	Reference
1	Clean Growth Initiative - EV DCFC	$ -	$ 1.560	$ 0.248	
2	Exogenous Factor - MRS	0.935	0.870	-	
3	Forecast Capital Expenditures	$ 0.935	$ 2.430	$ 0.248	Section 11, Schedule 4, Line 10

7.2.2.1 EV DCFC Stations

As discussed in Section 5.8, FBC's EV DCFC stations are prescribed undertakings under section 5 of the GGRR[40], and the cost of service associated with EV charging stations is subject to flow-through treatment. Please refer to Table 5-2 of Section 5.8 which provides a summary of the EV DCFC stations' costs and revenues from 2021 Actual to 2023 Forecast.

Table 7-11 above shows the EV DCFC stations capital expenditures for 2022 Approved[41], 2022 Projected, and 2023 Forecast. FBC originally did not forecast any EV DCFC station capital in 2022 during the 2022 Annual Review as FBC expected all construction activities to be completed in 2021. However, the originally planned construction activities in 2021 were delayed to 2022 mainly due to the flooding experienced in the latter part of 2021 which also led to FBC being required to undergo design changes to 16 of its DCFC sites to complete a required safety retrofit for the power supply kiosks. The flooding caused delays in construction and deployment for two planned DCFC stations in Keremeos and Princeton that were identified in FBC's Revised and Updated Application for EV DCFC Service and approved by Order G-215-21[42]. This resulted in an increase in capital expenditures for 2022 Projected when compared to 2022 Approved. FBC notes the reduction in expenditures for 2021 due to the delayed deployment of the Keremeos and Princeton stations was offset by the installation of two new DCFC stations in late 2021 at existing sites (i.e., Naramata and Grand Forks). Installations at Keremeos and Princeton are planned to be completed by the end of 2022, which by then will bring the total number of DCFC stations in service to 42 across the 23 sites. At this time, FBC is not expecting to construct any additional

[40] Order G-215-21 dated July 14, 2021.
[41] Consistent with the 2022 Annual Review Decision, FBC included the 2022 forecast revenues and expenses associated with the EV DCFC stations in the Compliance Filing to the Annual Review Decision and Order G-374-21 because approval of the EV DCFC Service Application was not received until November 24, 2021. Accordingly, the 2022 Approved amount reflected in Table 7-11 is the amount included in the Compliance Filing.
[42] FBC's Revised and Updated EV DCFC Service Application, Table 2-2, pp. 10-11.

stations or sites beyond the two additional DCFC stations noted above; however, station utilization will continue to be monitored to determine if any additional stations are warranted to meet customer demand. For 2023, FBC is forecasting to complete accessibility improvements for its existing EV DCFC sites. These improvements include new or additional lighting as the stations are available for use 24 hours a day, and paving for wheelchairs access to the charger.

The two new DCFC stations were installed at the existing Naramata and Grand Forks sites that only have a single DCFC station installed previously. Both Naramata and Grand Forks were identified in FBC's Revised Application for EV DCFC Service, and construction of these two additional stations was completed in late 2021. As directed by Order G-341-21[43], FBC is to include evaluation of any additional EV charging stations that were not originally identified in the Revised EV DCFC Service Application in FBC's Annual Review process, including review of whether the additional stations meet the criteria to be a prescribed undertaking under the GGRR and assessment of whether the levelized rate under RS 96 EV DCFC service will need to be recalculated as a result of the additional EV charging stations. Consistent with the information provided in FBC's Revised EV DCFC Application, Table 7-12 below shows that these two additional stations are prescribed undertakings and meet the requirements as set out in section 5 of the GGRR. Regarding the review of the levelized rate under RS 96 EV DCFC service, as discussed in Section 5.8, FBC is required to file a detailed assessment of the EV DCFC service by the end of December 31, 2022, which includes an update of the financial models with actual and forecast information as well as a detailed assessment of RS 96 and alternative rate design options. For the purposes of regulatory efficiency, FBC will address the review of the levelized rate under RS 96 EV DCFC service in the assessment report.

Table 7-12: Assessment of New EV DCFC Stations as Prescribed Undertakings Under the GGRR

	Greenhouse Gas Reduction Regulation Criteria						
GGRR Section	5(1)(a)	5(1)(b)	5(1)(c)	5(2)(a)	5(2)(b)(i)	5(2)(a)(ii)	5(2)(c)
	Station is available for use 24 hours a day by any member of the public	Station does not require users to be members of a charging network	Station is capable of charging electric vehicles of more than one make	Eligible charging station is constructed and operated or purchased and operated by the public utility	The public utility reasonably expects, on the date the public utility decides to construct or purchase an eligible charging station, that		For any eligible charging station coming into operation on or after January 1, 2022, the station uses or is configured to use the Open Charge Point Protocol.
					The station will come into operation by December 31, 2025. (Operation Date)	Is the station located in a limited municipality? (Population – 2021 Census)	
Sites							
Naramata	Yes	Yes	Yes	Yes	Q4 2021	No[1]	Yes
Grand Forks	Yes	Yes	Yes	Yes	Q4 2021	No (4,112)	Yes

[43] Decision and Order G-341-21, p. 27.

Note to Table:

[1] Not located in a municipality as defined by the Community Charter.

7.2.2.2 Mandatory Reliability Standards Incremental Capital

As explained in Section 6.3.5, the incremental capital expenditures related to the adoption of MRS AR13 were approved for exogenous factor treatment in the 2022 Annual Review Decision. These costs are for the implementation of changes/additions, including the development and implementation of methods to monitor network traffic and software tools to support the changes/additions to the standards. The implementation of the required changes/additions requires the purchase and installation of hardware and software to assess and evaluate network traffic and the development of software tools to track risk assessments of any product or service procured for Bulk Electrical System assets.

Table 7-13 below shows the incremental capital expenditures related to MRS AR13 with a breakdown between labour, non-labour and contingency for 2022 Approved, 2022 Projected and 2023 Forecast.

Table 7-13: Incremental Capital Expenditures for MRS AR13 ($ millions)

Line No.	Description	Approved 2022	Projected 2022	Forecast 2023	Reference
1	Labour	$ 0.580	$ 0.680	$ -	
2	Non-Labour	0.205	0.140	-	
3	Contingency	0.150	0.050	-	
4	Total	$ 0.935	$ 0.870	-	Section 11, Schedule 4, Line 8

As shown in the table above, the 2022 Projected capital expenditures are approximately $0.065 million less than 2022 Approved. The reason for the variance is that FBC was able to purchase some software early (i.e., at the end of 2021 instead of 2022). Overall, there is no change to the original total estimate of $0.935 million (i.e., $0.065 million in 2021 Actual and $0.870 million in 2022 Projected).

As explained in the 2022 Annual Review[44], FBC is not expecting any incremental capital costs for 2023; therefore, the 2023 Forecast is zero. As the capital expenditures related to MRS AR13 are approved for flow-through treatment, any variances from Projected and Forecast amounts for the adoption of MRS AR13 will be trued up by way of the Flow-through deferral account and returned to, or recovered from, customers in future years.

7.3 MAJOR PROJECTS CAPITAL EXPENDITURES

Major Projects are capital expenditures that do not form part of regular capital spending as they are approved through a separate CPCN or other application. As part of the MRP Decision,[45] the

[44] Exhibit B-3, BCUC IR1 24.2.
[45] MRP Decision and Order G-166-20, pp. 132-133.

BCUC approved the continuation of the current process of reviewing Major Projects outside of the proposed MRP and approved the continuation of the existing financial threshold for CPCNs of $20 million for FBC for the MRP term.

For 2023, FBC is forecasting capital expenditures related to the KBTA project only. However, FBC's 2023 Forecast rate base also includes the full-year impact of capital additions related to the Corra Linn Dam Spillway Gate Replacement project, the UBO Old Units Refurbishment project, and the Playmor Substation Upgrade project, all of which are expected to complete in 2022. Each of these approved projects is described further below.

KBTA Project

The KBTA project was approved by Order C-4-20 and involves the installation of a third terminal transformer at the F.A. Lee Terminal Station, including the reconfiguration of the 138 kV bus into an industry standard ring bus configuration. The new transformer is scheduled to be in service by the end of 2022 or early 2023, with project close-out in 2023, at an estimated cost of $23.288 million, inclusive of AFUDC and cost of removal. FBC forecasts capital expenditures of $11.384 million and $1.710 million (excluding AFUDC) in 2022 and 2023, respectively, with $21.250 million to be added to rate base on January 1, 2023 and the remainder added to rate base on January 1, 2024.

Corra Linn Dam Spillway Gate Replacement Project

The Corra Linn Dam Spillway Gate Replacement project was approved by Order C-1-17 and involves the replacement of 14 spillway gates and upgrades to the associated infrastructure. The project is expected to be complete in 2022 at a cost of $79.727 million, inclusive of AFUDC and cost of removal. Thus, FBC is not forecasting any capital expenditures related to this project in 2023. Since 2020, a total of $51.768 million has been added to FBC's rate base with the remaining $16.151 million forecast to be added to rate base in 2023. Overall, $67.919 million is forecast to be added to rate base by January 1, 2023 ($51.768 million of actual from 2020 to 2022 plus $16.151 million of 2023 Forecast), plus $11.808 million of cost of removal, for a total estimated project cost of $79.727 million including AFUDC and cost of removal.

UBO Old Units Refurbishment Project

The UBO Old Units Refurbishment project was approved by Order G-8-17 and involves the refurbishment of four generating units that are more than 100 years old. The refurbishments were completed in 2021 at an estimated total project cost of $34.180 million, inclusive of AFUDC and cost of removal. FBC is projecting approximately $0.002 million of remaining close-out costs in 2022 which will be added to rate base January 1, 2023. Overall, $32.290 million is forecast to be added to rate base by January 1, 2023 ($32.288 million of actual from 2018 to 2022 and $0.002 million of 2023 Forecast), plus $1.890 million of cost of removal, for a total estimated project cost of $34.180 million including AFUDC and cost of removal. As directed by the BCUC in the Annual Review for 2017 Rates, the UBO Refurbishment Project Final Report is included as Appendix B2.

Playmor Substation Upgrade Project

The Playmor Substation Upgrade project was approved by Order G-42-21 and involves rebuilding the Playmor substation in South Slocan, BC on an expanded station footprint in order to increase station capacity. The project is expected to be complete in 2022 at an estimated cost of $8.036 million, inclusive of AFUDC, and approximately $0.300 million of cost of removal. As the project is expected to complete in 2022, FBC is not forecasting any capital expenditures related to this project in 2023, and all project costs, estimated to be $8.036 million (including AFUDC) are forecast to enter rate base on January 1, 2023, with $0.300 million to be recorded to cost of removal.

7.4 2023 PLANT ADDITIONS

The 2023 Plant Additions are comprised of: (i) FBC's 2023 regular capital expenditures from Section 7.2; (ii) the Major Projects from Section 7.3 to the extent that portions of those projects are placed into service; (iii) the change in work in progress which adjusts for capital expenditures for projects that are in progress at year-end; (iv) AFUDC; and (v) overhead capitalized for the year. A reconciliation of capital expenditures to plant additions is shown below and is also provided in Section 11, Schedule 5.

Table 7-14: Reconciliation of 2023 Capital Expenditures to Plant Additions ($ millions)

Line No.	Description		Forecast 2023	Reference
1	Forecast Capital Expenditures	$	94.428	Section 11, Schedule 5, Line 2
2	Flow-Through Capital Expenditures		0.248	Section 11, Schedule 5, Line 3
3	Total Gross Regular Capital Expenditures		94.676	Sum of Lines 1 and 2
4				
5	Capitalized Overhead		10.918	Section 11, Schedule 5, Line 16
6	AFUDC		0.243	Section 11, Schedule 5, Line 17
7	Change in Work in Progress		-	Section 11, Schedule 5, Line 19
8	Total Regular Additions to Plant		**105.837**	Sum of Lines 3 through 7
9				
10	Special Projects and CPCN Capital Expenditures			
11	Kelowna Bulk Transformer Capacity Addition		1.710	Section 11, Schedule 5, Line 7
12	AFUDC		0.049	Section 11, Schedule 5, Line 23
13	Change in Work in Progress		43.680	Section 11, Schedule 5, Line 25
14	Total Special Projects and CPCN Additions to Plant		**45.439**	Sum of Lines 11 through 13
15				
16	Total Plant Additions	**$**	**151.276**	Line 8 + Line 14

7.5 ACCUMULATED DEPRECIATION

Rate base includes both the accumulated depreciation on plant in service and accumulated amortization of CIAC. Both are increased through depreciation expense and decreased through retirements.

The depreciation rates used for 2023, which were approved by Order G-166-20 and are based on FBC's most recent depreciation study, include the recovery of the estimated future costs of removal over the average service life of the assets (net salvage) in accumulated depreciation. Depreciation is calculated beginning January 1 of the year after the assets are placed in service, which is the treatment approved by Order G-139-14.

Based on calculating depreciation expense at these approved depreciation rates on the opening plant-in-service balance, the 2023 depreciation expense is calculated as $64.407 million.[46]

7.6 *DEFERRED CHARGES*

On May 3, 2017, the BCUC issued its Regulatory Account Filing Checklist.[47] The stated purpose of the checklist is to assist regulated entities when filing regulatory account requests and to facilitate an efficient review by the BCUC.

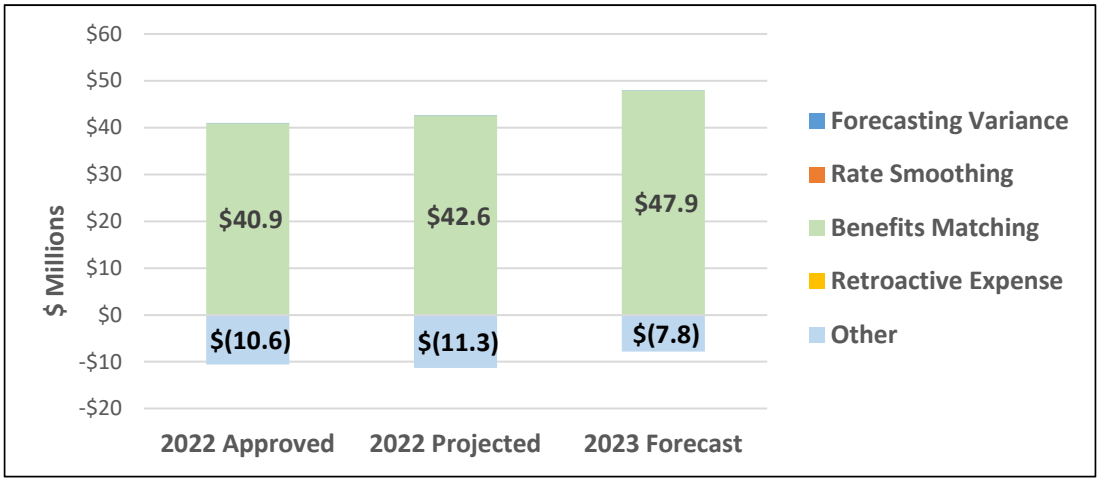
The checklist classifies deferral accounts as one of: (a) forecast variance account; (b) rate smoothing account; (c) benefit matching (capital-like) account; (d) retroactive expense account; or (e) other. In Section 11, Schedule 11, FBC has classified its rate base deferral accounts in accordance with this classification.

The 2023 Forecast mid-year balance of unamortized deferred charges in rate base for FBC is a debit of $40.045 million. The 2023 debit balance is driven largely by the balances in the Demand Side Management (DSM) and Deferred Debt Issue Costs deferral accounts, partially offset by the Pension and OPEB Liability deferral account.

Figure 7-1 provides the mid-year deferral account balances summarized by deferral account category.

[46] $69.474 million depreciation expense as shown in Section 11, Schedule 21, Line 2 less $5.067 million amortization of CIAC as shown in Section 11, Schedule 21, Line 8.
[47] BCUC Letter, Log No. 53608, Appendix B.

Figure 7-1: FBC Forecast Mid-Year Balances of Rate Base Deferral Accounts by Category



Based on amortizing the opening deferral account balances (rate base and non-rate base) using the approved and proposed amortization periods, the 2023 amortization expense is calculated as a credit of $3.277 million.[48] The subsections below include a discussion on new rate base deferral accounts and changes or updates to existing rate base deferral accounts. For a discussion on non-rate base deferral accounts, please refer to Section 12.

7.6.1 New Deferral Accounts

FBC is seeking approval to create one new rate base deferral account in this Application, as discussed below.

7.6.1.1 Joint Pole Use Audit 2023

Under the provisions of FBC's various joint use pole agreements, the parties are required to perform an audit of the joint use pole contacts once every five years, the last of which occurred in 2018.

Consistent with past treatment of costs for joint pole use audits, FBC is seeking approval to establish a rate base deferral account to capture costs incurred for the 2023 Joint Use Pole Audit, which are estimated at $0.435 million ($0.318 million after tax) to be incurred in 2023.

FBC is also requesting approval to amortize these costs over a five-year period beginning January 1, 2023, which represents the time period between the required audits.

Table 7-15 below addresses the considerations identified in the Regulatory Account Filing Checklist as they pertain to the above-described deferral account request.

[48] Section 11, Schedule 21, Column 3, Sum of Line 5 and 6.

Table 7-15: Deferral Account Filing Considerations

Item	Consideration	Joint Pole Use Audit 2023
I.	Indicate if the request is: (a) for a modification or a change in scope to an existing Commission approved regulatory account; or (b) to establish a new regulatory account.	The 2023 Joint Pole Use Audit deferral account is a new deferral account, consistent with the past treatment of joint pole use audits in previous years.
a)	If the request is for a modification or change in scope to an existing regulatory account, explain why the existing regulatory account is an appropriate account to use (specifically addressing the existing account's intended and approved purpose, mechanism for recovery, timeline for recovery and carrying costs).	N/A
b)	If the request is for approval of a new regulatory account, state the purpose of the regulatory account and explain its intended use.	The purpose of the requested account is to capture costs related to joint use pole audits that are required once every five years.
II.	Propose a term (i.e. length of time) that the regulatory account should be approved for and explain why that term is appropriate.	The term of the account encompasses the conduct of the audit and subsequent amortization period, equivalent to the term of the benefit.
III.	Identify any alternate treatments that were considered, including an overview of what the accounting treatment would be in the absence of approval of the request to establish a regulatory account, and explain why these alternate treatments may not be appropriate.	In the absence of a deferral account, the costs of the audit would have to be forecast as an O&M expense (outside of the MRP formula O&M since the 2018 audit costs were deferred and excluded from Base O&M Expense) and trued up annually by way of the Flow-Through deferral account. FBC considers a deferral account to be the more appropriate treatment since it permits the amortization of costs over the five-year period between audits.
IV a)	Address: whether, or to what extent, the item is outside of management's control;	An audit of joint use poles is required at five-year intervals as a condition of FBC's agreements with the counter parties and is therefore outside of FBC's direct control.
b)	the degree of forecast uncertainty associated with the item;	FBC forecasts audit costs based on past experience. Actual costs are recorded in the account so that the actual, not forecast, costs are recovered in rates.
c)	the materiality of the costs	Refer to Section 7.6.1.1.
d)	any impact on intergenerational equity	FBC proposes to recover the deferred costs over the five-year period between the required audits.
V.	Classify the regulatory account as either: (a) forecast variance account; (b) rate smoothing account; (c) benefit matching account; (d) retroactive expense account; or (e) other.	FBC classifies this account as a benefit matching account since the costs are recovered over the period between audits.
VI.	Identify if the regulatory account is a cash or non-cash account.	The joint use pole audit account is a cash account.

Item	Consideration	Joint Pole Use Audit 2023
VII.	Specify what additions to the regulatory account are being requested (i.e. type and amount of additions), including whether the account is intended to capture additions for a specific period of time or on an ongoing basis.	Costs include incremental labour, vehicle, and staff expense in addition to FBC's share of common costs such as data input costs. See Section 7.6.1.1.
VIII.	Propose a mechanism for recovery (e.g. how the balance in the regulatory account will be recovered or refunded to ratepayers) and explain why it is appropriate.	Costs are recovered in revenue requirements by way of amortization expense.
IX.	Propose a timeline for recovery (e.g. the period over which the regulatory account balance is either collected or refunded; also referred to as the amortization period) and explain why it is appropriate.	FBC proposes to recover the deferred costs over the five-year period between the required audits.
X.	Propose a carrying cost for the balance in the regulatory account and explain why it is appropriate.	Rate base deferral accounts are included in rate base and are therefore implicitly financed using the weighted average cost of capital (WACC).
XI.	Outline a recommended regulatory process for the Commission's review of the application.	The proposed deferral account can be reviewed as part of the present proceeding. Deferral account approvals and disposition are generally determined in revenue requirement proceedings. Where requested within CPCNs or other applications, the regulatory process will be included within the draft timetable for each specific application.

7.6.2 Existing Deferral Accounts

In the discussion below, FBC provides information on two existing deferral accounts and requests approval of an amortization period for one of them.

7.6.2.1 COVID-19 Customer Recovery Fund Deferral Account

7.6.2.1.1 DESCRIPTION AND FINANCIAL ESTIMATES

In June 2020, FBC received approval through Order G-133-20 to establish the COVID-19 Customer Recovery Fund Deferral Account in rate base to record three items:

1. any bill payment deferrals provided to customers due to the COVID-19 pandemic and subsequent payments of those deferred amounts;
2. any bill credits provided to customers due to the COVID-19 pandemic; and
3. any unrecovered revenue resulting from customers being unable to pay their bills due to the COVID-19 pandemic, which will be tracked separately by rate schedule.

The following section provides 2022 and 2023 financial estimates and descriptions for each of the three items approved for inclusion in the COVID-19 Customer Recovery Fund Deferral Account. FBC also proposes to commence amortization of the deferral account balance in 2023 and to discontinue quarterly reporting.

(a) Bill payment deferrals provided to residential and small commercial customers

The bill payment deferral program was offered to residential and small commercial customers affected by the COVID-19 pandemic. FBC experienced high collection rates in regard to this program, recovering approximately 85 percent of the outstanding balances through the regular monthly instalments. The remaining customer balances that were ultimately deemed unrecoverable have been designated as unrecoverable revenue and as such, a total of $0.119 million has been transferred to the COVID-19 Customer Recovery Fund Deferral Account. These additions to the deferral account are forecast in section (c), Table 7-18 *Unrecoverable Revenue Amounts*.

FBC ceased accepting new applications effective June 1, 2021 and is therefore not forecasting further additions related to this relief measure.

Table 7-16: Bill Payment Deferral Forecast Amounts ($ millions)

	2020 Actual	2021 Actual	2022 Projected	2023 Forecast
Opening Balance	-	0.563	0.005	-
Additions	0.803	-	-	-
Repayments	(0.240)	(0.444)	-	-
Transfers	-	(0.114)	(0.005)	-
Ending Balance	0.563	0.005	-	-

(b) Bill credits provided to small commercial customers

The bill credit program offered to small commercial customers has been calculated using the existing balance of $0.132 million as of April 2022. Given the duration and period these credits were available for, as well as the June 1, 2021 closure of the program for new applications, FBC does not expect additional credits to be offered to customers throughout the remainder of 2022 or in 2023. As such, FBC is proposing to amortize the $0.132 million over three years, with the 2023 amortization amount shown in Table 7-17 below.

Table 7-17: Bill Credit Amounts ($ millions)

	2020 Actual	2021 Actual	2022 Projected	2023 Forecast
Opening Balance	-	0.130	0.132	0.132
Additions	0.178	0.003	-	-
Tax	(0.048)	(0.001)	-	-
Amortization[49]	-	-	-	(0.044)
Ending Balance	0.130	0.132	0.132	0.088

[49] Based on a requested three-year amortization period, as discussed in Section 7.6.2.1.2.

(c) Unrecovered revenue resulting from customers being unable to pay their bills due to the COVID-19 pandemic

This portion of the deferral account forecast represents the amount of customer balances owing (i.e., account receivables) that are recognized as unrecoverable due to the COVID-19 pandemic. As such, these amounts are in excess of the normal course forecast bad debt expense that is recognized in indexed-based O&M.

Table 7-18: Unrecoverable Revenue Amounts ($ millions)

	2020 Actual	2021 Actual	2022 Projected	2023 Forecast
Opening Balance	-	0.011	0.134	0.375
Transfers[50]	-	0.114	0.005	-
Additions[51]	0.015	0.054	0.325	-
Tax	(0.004)	(0.045)	(0.089)	-
Amortization[49]	-	-	-	(0.125)
Ending Balance	0.011	0.134	0.375	0.250

The unrecovered revenue recorded in the deferral account includes:

- any remaining balances associated with the bill payment deferral program, described in section (a), that resulted from customers' inability to pay (shown as the Transfers line in Table 7-18 above); and
- any unrecovered revenue from all customer classes due to the COVID-19 pandemic, including industrial and large commercial customers and those residential and small commercial customers that did not participate in the bill payment deferral or bill credit relief offerings (shown as the Additions line in Table 7-18 above).

The 2022 Projected transfers of $0.005 million represent the actual 2022 transfers for the months available and any remaining bill payment deferral loan balances that were not yet repaid. The 2022 Projected additions of $0.325 million have been calculated using actual additions for the months available with the remainder of the year forecast using an approach consistent with the prior year. That is, a factor of 15 percent has been applied to the total outstanding balance of customer accounts that are past due as at March 1, 2022. This approach was based on a pilot outreach program in 2021 where 15 percent of customers with an average balance of $800 confirmed that they were financially impacted by the COVID-19 pandemic and required support to bring their account into good standing.

[50] The actual 2021 unrecoverable revenue transfers of $0.114 million consist of $0.004 million of small commercial customer balances and $0.110 million of residential customer balances.

[51] The actual 2020 unrecoverable revenue additions of $0.015 million consist of $0.014 million of small commercial customer balances and $0.001 million of residential customer balances. The actual 2021 unrecoverable revenue additions of $0.054 million consist of $0.004 million of small commercial customer balances and $0.050 million of residential customer balances.

While the forecasts of the unrecovered revenue additions above rely on estimates and broader macroeconomic factors, the actual amounts that will be recorded in the deferral account will reflect actual balances that are attributable to specific customers that cannot make payment due to the COVID-19 pandemic.

In this regard, to support the development of a consistent and appropriate approach for identifying amounts deemed unrecoverable due to COVID-19, FBC has created an internal set of guidelines to be used by members of the customer service team with an objective to identify and support customers that have been financially impacted by the COVID-19 pandemic. The underlying goal and intent of this approach is for customers to be able to maintain their gas services while maximizing recoveries associated with any balances due. These internal guidelines include questions that help identify the extent to which the customer has been impacted by COVID-19 as well as payment arrangement guidelines that include partial or full recognition of receivable balances as unrecoverable due to the COVID-19 pandemic.

7.6.2.1.2 DISPOSITION OF DEFERRAL ACCOUNT

As indicated in the 2022 Annual Review, additions to the COVID-19 Customer Recovery Fund Deferral Account for unrecovered revenues resulting from customers being unable to pay their bills due to the COVID-19 pandemic were expected to continue into 2022. As such, FBC has continued to capture unrecovered revenues in this deferral account during 2022.

Since the 2022 Annual Review, conditions have improved such that most COVID-19 pandemic restrictions in BC have been lifted.[52] The Federal government support programs such as the Canada Emergency Response Benefit (CERB) and the Canada Emergency Wage Subsidy (CEWS) for businesses have ended as the impact of the COVID-19 pandemic lessens. This, along with the improved economic conditions, although somewhat tempered recently with inflationary and recessionary considerations, suggests that ongoing pandemic support is not needed anymore.

Additionally, FBC has resumed most of its collection practices in 2022 with no significant uptick in unrecoverable revenues from customers experienced so far, and FBC anticipates full resumption of normal collection practices by mid-2022.

As a result, based on the positive current outlook for the COVID-19 pandemic and the lessened impact, FBC does not anticipate any further additions to the deferral account after 2022 and proposes to commence amortization of the balance in the deferral account on January 1, 2023 using a three-year amortization period. FBC considers a three-year amortization period to be appropriate because it matches the number of years during which the COVID-19 Customer Recovery Fund Deferral Account was active (i.e., 2020 through 2022).

Should public health and economic conditions deteriorate significantly due to the resurgence of the COVID-19 pandemic later this year or in the future (i.e., another wave of the pandemic which causes shutdowns and job losses impacting individuals and businesses), FBC may seek BCUC

[52] See Section 12.2.1 for further discussion and details.

approval again for deferral account treatment for the same purpose and reasons set out in the 2020 application.

7.6.2.1.3 REQUEST TO DISCONTINUE REPORTING

FBC seeks approval to discontinue the existing quarterly reporting requirements for the COVID-19 Customer Recovery Fund Deferral Account filed with the BCUC. If approved, the final quarterly report would be for Q4 2022 and would be submitted in Q1 2023.

With more than two full years of reporting complete, the closure of the deferral and credit program to new applicants as of June 1, 2021, and the planned discontinuation of additions to the deferral account as of December 31, 2022, FBC does not see further value in providing separate detailed reporting for this account.

7.6.2.2 Indigenous Relations Agreement (Huth Substation)

As part of the Annual Review for 2020 and 2021 Rates Decision and Order G-42-21, FBC received approval to establish the Indigenous Relations Agreement (Huth Substation) deferral account to capture costs to address the Penticton Indian Band's (PIB) concerns regarding the Huth Substation in Penticton and the impacts the substation has had on Syilx[53] history and culture, such as the discovery of ancestral remains found at the Huth substation while performing construction works.

The Huth substation is a vital component of the South Okanagan area power system, providing direct service to both FBC customers and the municipal utility of the City of Penticton. This hub is connected to five major transmission lines (42L, 49L, 47L, 52L and 53L) and to two City of Penticton distribution substations. Given the importance of the substation to the supply of power in the South Okanagan and the historical value of the land to the PIB and the Syilx people, FBC has engaged in reconciliation efforts with the PIB, consistent with the recent legislation passed by the Provincial government.

FBC stated in the 2020-2021 Annual Review that it would update its progress with respect to this matter in future annual reviews and request approval for recovery of costs captured in this deferral account once an agreement with the PIB had been reached and the impacts could be communicated.

FBC has been unable to continue preliminary discussions with the PIB on reconciliation efforts on the Huth substation. Due to impacts on the community from the COVID-19 pandemic, followed by the unique circumstances that arose in 2021 with the Kamloops Residential School findings, and as the Penticton Indian Band and FortisBC Energy Inc. are currently in discussions regarding the proposed Okanagan Capacity Upgrade project, FBC chose not to pursue further efforts regarding the Huth Substation until both parties agreed to proceed. FBC will continue to provide updates on this matter and on the deferral account in future annual review filings.

[53] The PIB is a community of the Syilx people.

7.7 WORKING CAPITAL

The working capital component of rate base is comprised of cash working capital and other working capital.

Cash working capital is defined as the average amount of capital provided by investors in the Company to bridge the gap between the time expenditures are required to provide service (expense lag) and the time collections are received for that service (revenue lag). The cash working capital requirements that have been included reflect the most recent Lead Lag Study results, as approved through Order G-166-20.

Other working capital includes customer (DSM) loans, employee loans and withholdings, and inventory of materials and supplies. 2023 amounts are forecast based on 2021 Actual levels.

7.8 SUMMARY

FBC's rate base includes the impact of regular and Major Project capital expenditures, adjusted for work-in-progress, AFUDC and overheads capitalized. FBC has provided forecasts for all of its rate base deferral accounts in the financial schedules included in Section 11. In Section 7.2.1, FBC requested approval of its updated 2023 and 2024 regular capital (growth, sustainment and other) forecasts; in Section 7.6.1, FBC requested approval of one new deferral account; and in Section 7.6.2, FBC discussed two existing accounts, including requesting amortization of one of these existing accounts. Finally, the rate base includes cash and other working capital.

8. FINANCING AND RETURN OF EQUITY

8.1 INTRODUCTION AND OVERVIEW

FBC has prepared this Application using a capital structure of 60 percent debt and 40 percent equity and a Return on Equity (ROE) of 9.15 percent as approved by Orders G-129-16 and G-47-14. FBC's ROE is set at a premium of 40 basis points over the benchmark ROE, which is the ROE approved for FEI.

FBC is currently participating in the BCUC-initiated Generic Cost of Capital (GCOC) proceeding and has filed evidence on its recommended capital structure and ROE as part of Stage 1 of the proceeding. In Order G-156-21 and accompanying Reasons for Decision, the BCUC found that the effective date to implement a new cost of capital will depend on the timing and progress of the GCOC proceeding. As explained in Section 1.2, FBC is seeking approval of interim 2023 rates pending the outcome of Stage 1 of the GCOC proceeding as well as a decision on FBC's 2023-2027 DSM Expenditure Plan. When a decision is reached on these proceedings, FBC will update its rate calculations and apply for permanent 2023 rates.

The 2023 Forecast for financing costs, including the interest expense on issued long- and short-term debt and on new issuances that are forecast, has been updated as described in Section 8.3 below. Based on the updated financing costs, FBC's AFUDC rate for 2023 (which is equal to its after-tax weighted average cost of capital) is 5.73 percent. Any variances from interest rates used to set rates, and any variances in interest resulting from items subject to flow-through in the Flow-through deferral account, will be flowed through to customers. All other differences in interest expense will affect the achieved ROE and be subject to earnings sharing.

8.2 CAPITAL STRUCTURE AND RETURN ON EQUITY

The Company finances its investment in rate base assets with a mix of debt and equity, as approved by the BCUC from time to time. Order G-47-14 approved a capital structure for FBC of 60.0 percent debt and 40.0 percent equity with an equity risk premium of 40 basis points over the benchmark ROE, which was set at 8.75 percent by Order G-129-16; these approved capital structure and ROE values have been used to calculate rates in the Application.

8.3 FINANCING COSTS

Debt financing costs include the borrowing costs on issued debt as well as on new issuances that are forecast. Debt consists of both long- and short-term debt.

8.3.1 Long-Term Debt

FBC is both a private and public issuer of long-term debt. In March 2022, FBC issued long-term debt of $100 million at a rate of 4.16 percent for a term of 30 years. The net proceeds were used to repay existing indebtedness and finance the Company's capital expenditure program. FBC

plans to issue additional long-term debt of approximately $75 million in 2023 and will use the funds for the same purposes. The 2023 debt issuance is reflected in the financial schedules in July 2023 at a rate of 4.90 percent.[54] The exact timing, amount and rate of the 2023 issuance will depend on future market conditions and capital expenditure requirements. Variances in interest expense related to the timing and amount of the issuances of the debt or the rates at which they are issued will be captured in the Flow-through deferral account.

8.3.2 Short-Term Debt

FBC obtains short-term funding primarily through the issuance of commercial paper to Canadian institutional investors. FBC backstops the commercial paper issuances by maintaining a $150 million committed credit facility that matures in April 2026.[55] This facility is also used to issue letters of credit. The credit facility, along with a $10 million overdraft facility, provides FBC with short-term liquidity to fund its capital program and working capital requirements.

8.3.3 Forecast of Interest Rates

FBC uses interest rate forecasts to estimate future interest expense. Forecasts of Treasury Bills and benchmark Government of Canada Bond interest rates are used in determining the overall interest rates for short-term debt and for rates on new issues of long-term debt, respectively. The forecasts are based on available projections made by Canadian Chartered banks.

Credit spreads on new long-term debt are based on current indicative rates, on the assumption that the current credit ratings of FBC are maintained.

FBC's short-term borrowing rate is based on the rate at which it issues commercial paper. Since commercial paper issuance rates are not forecast by economists, a forecast needs to be derived by FBC. The forecast is based on the historical differential between the Canadian Deposit Overnight Rate (CDOR) and the rate obtained by FBC under its commercial paper program. CDOR is used because FBC's short-term borrowings under its credit facility are priced based on CDOR and therefore CDOR is tracked relative to FBC's commercial paper borrowings. As CDOR is not forecast by economists, FBC must first obtain the 3-Month T-Bill rate forecast and then convert it to a CDOR forecast. FBC does this by taking the 3-year historical spread between CDOR and the 3-month T-Bill rate. Then, to derive the short-term borrowing rate forecast, FBC adjusts the CDOR forecast with the historical spread between CDOR and rates of issuances under its commercial paper program.

The 3-Month T-Bill forecast for 2023 is 3.14 percent, which is a significant increase from the 0.47 percent approved in 2022. FBC is in a rising interest rate environment due to high inflation, Russia's invasion in Ukraine, and the removal of monetary policy actions that were prevalent during the initial years of the COVID-19 pandemic (i.e., 2020 and 2021). In addition, on July 13, 2022 the Bank of Canada completed its fourth rate hike of the year, raising the benchmark interest

[54] Section 11, Schedule 27, Line 10.
[55] On July 14, 2021, the credit facility was extended to April 27, 2026.

rate to 2.5 percent from 0.25 percent at the beginning of 2022 and signalling that more rate hikes will be announced in 2022. The market volatility is expected to persist given many ongoing elevated risk variables.

For 2023, FBC forecasts a similar level of other financing fees to the 2022 Approved amount. Other financing fees include the fees that FBC incurs for its letters of credit under the $150 million credit facility, as well as interest paid on customer deposits. The short-term borrowing rate forecast is shown in Table 8-1 below.

Table 8-1: Short Term Interest Rate Forecast

FBC Short Term Interest Rate	Approved 2022	Projected 2022	Forecasted 2023
3-Month T-Bill Rate [1]	0.47%	3.08%	3.14%
Spread to CDOR	0.39%	0.36%	0.36%
CDOR Rate	0.86%	3.44%	3.50%
Spread to CP	-0.32%	-0.36%	-0.36%
CP Dealer Commission	0.10%	0.10%	0.10%
ST Interest Rate on Credit Facilities	**0.64%**	**3.18%**	**3.24%**
Fixed Financing Fees [2]			
Standby fee on Undrawn Credit [3]	0.44%	0.39%	0.44%
Renewal Fee on Undrawn Credit	0.17%	0.11%	0.12%
Other Financing Fees	0.26%	0.35%	0.44%
ST Interest Rate on Fixed Financing Fee	**0.87%**	**0.84%**	**1.00%**
FBC Short Term Rate	**1.51%**	**4.02%**	**4.24%**

Notes to Table:

[1] 3-Month T-Bill Rate for 2023 is a weighted average rate based on forecasts provided by Canadian Chartered banks in July 2022.

[2] Fixed financing fees represent the costs of maintaining the $150 million credit facility and letter of credit facility, which are fixed fees incurred regardless of whether FBC draws from the credit facility. The fees have been converted into a short-term rate for forecast purposes.

[3] A standby fee of 20 bps is charged on undrawn credit facility amounts, which would change if credit facility amounts are drawn through banker acceptances or prime loans. However, the forecast assumes FBC will borrow through commercial paper and will not change the undrawn credit facility fee percentage.

4. Other financing fees include commercial paper issuance fees, letter of credit fees, customer deposit interest expense and miscellaneous bank administration costs. The letter of credit fees, customer deposit interest and miscellaneous bank administration costs are incurred regardless of whether FBC draws from the credit facility.

As noted above, FBC's interest rate forecasts are based on CDOR. An indirect result of the cessation of the publication of the London Interbank Offered Rate (LIBOR) is that Canada is reassessing its use of CDOR as a risk-free rate benchmark for financial instruments in multiple asset classes. This will impact FBC's credit facility agreement as Refinitiv Benchmark Services (UK) Limited (RBSL), CDOR's regulated administrator, announced that CDOR will cease to be published after June 28, 2024.[56] The Canadian Alternative Reference Rate Working Group

[56] https://www.bankofcanada.ca/markets/canadian-alternative-reference-rate-working-group/.

(CARR) was established to coordinate the transition to a new risk-free rate benchmark. It is anticipated that CDOR will transition to the Canadian Overnight Repo Rate Average (CORRA), a transaction-based overnight risk-free interest rate benchmark in existence since 1997.[57] FBC will work with its banking syndicate members to transition its credit facility agreement to CORRA and will revisit the methodology for short-term interest rate forecasting when such a transition is complete.

8.3.4 Interest Expense Forecast

The interest expense forecast reflects FBC's existing and forecast borrowing costs on long- and short-term debt.

Short-term interest expense is determined by applying the forecast short-term debt rate to the estimated short-term debt balance. Long-term debt interest expense is determined using the straight-line method by multiplying the average balance of the specific debenture by the debt coupon rate, or forecast coupon rate, if it is a new issue. The 2023 long-term debt schedule for FBC can be found in Section 11, Schedule 27.

8.3.5 Allowance for Funds Used During Construction (AFUDC)

FBC applies AFUDC to projects that are greater than three months in duration and greater than $100 thousand. Based on the above information, FBC's AFUDC rate for 2023 (which is equal to its after-tax weighted average cost of capital) is 5.73 percent. The calculation of the rate is shown in the following table.

Table 8-2: Calculation of AFUDC Rate for 2023

	Weight	Pre Tax Rate	After Tax Rate	Earned Return
Short Term Debt	5.44%	4.24%	3.10%	4.24%
Long Term Debt	54.56%	4.78%	3.49%	4.78%
Common Equity	40.00%	12.53%	9.15%	9.15%
Weighted Average	100.00%	7.85%	5.73%	6.50%

8.4 *SUMMARY*

FBC's equity financing and ROE have been forecast for 2023 at the same percentages as approved for 2022. FBC's debt financing costs on rate base are primarily determined by embedded rates on long-term debt, and to a lesser degree by short-term debt rates; the embedded rate on long-term debt is forecast to decrease in 2023 as compared to 2022 Approved.

[57] https://www.bankofcanada.ca/wp-content/uploads/2021/12/CARR-Review-CDOR-Analysis-Recommendations.pdf.

9. TAXES

9.1 INTRODUCTION AND OVERVIEW

This section discusses FBC's forecasts of property taxes and income tax which have been forecast on a basis consistent with prior years. In 2023, property taxes are forecast to increase by 2.1 percent from 2022 Approved, while income tax is forecast to decrease by 19.9 percent compared to 2022 Approved.

9.2 PROPERTY TAXES

Property taxes for 2023 of $18.260 million incorporate Company forecasts of assessed values of taxable assets, mill rates and taxes from revenues earned from electricity consumed within municipalities. A breakdown of property taxes by asset type is provided in Table 9-1 below.

Table 9-1: Property Taxes ($ millions)

Line No.	Description	Approved 2022	Projected 2022	Forecast 2023
1	Generating Plant	$ 3.210	$ 3.199	$ 3.253
2	Transmission and Distribution	7.428	6.950	7.189
3	Substation Equipment	3.948	4.156	4.208
4	Land and Buildings	1.165	1.201	1.322
5	In-Lieu	2.138	2.115	2.288
6	Total Property Taxes	$ 17.889	$ 17.621	$ 18.260
7				
8	Forecast Change from 2022 Approved			2.1%
9	Forecast Change from 2022 Projected			3.6%

As shown in the above table, in 2023 property taxes are forecast to increase by 2.1 percent from 2022 Approved and increase by 3.6 percent compared to 2022 Projected. In general, the 2023 increase from 2022 Projected is due to construction activities, market value changes, and changes in tax policies of local taxing authorities. The most significant drivers of the forecast changes are as follows:

1. **Changes in Tax Rates.** Tax Rates are expected to change for 2023 as follows:

   a) Municipal rates are expected to increase by 1.0 percent;

   b) School rates are expected to decrease by 1.0 percent;

   c) Rural rates are expected to decrease by 0.4 percent;

d) Tax rates on First Nations are expected to increase by 0.8 percent; and

e) Other rates are expected to decrease by 1.4 percent.

2. **Changes in Revenues to Calculate Grants In Lieu of Taxes.** Revenues reported to municipalities are expected to increase by 8.2 percent based on actual revenues applicable to the taxation year. Grants in-lieu of taxes are based on a fixed percentage of revenues; the overall actual increase in revenues reported to municipalities increases the grants in-lieu of taxes due.

3. **Changes in Assessed Values.** Forecast changes in the assessed values of FBC's property are based on expected inflationary increases. These include:

a) A 5.2 percent increase in assessed values of distribution lines and a 2.5 percent increase in transmission lines;

b) A 2.5 percent increase in assessed values for generating facilities calculated using legislated cost manuals for valuing generating facilities;

c) A 0.5 percent decrease in assessed values for substations calculated using legislated cost manuals for valuing substations; and

d) Land values are expected to increase between 4.3 percent to 11.4 percent for right of ways and properties owned in fee simple.

Any variances from the forecast of property taxes included in rates are recorded in the Flow-through deferral account and will be returned to or recovered from customers in the following year.

9.3 *INCOME TAX*

FBC is subject to corporate income taxes imposed by the Federal and BC governments. Current income taxes have been calculated using the flow-through (taxes payable) method, consistent with BCUC-approved past practice, at the corporate tax rate of 27 percent for 2023, which is unchanged from 2022. The corporate tax rates used in this Application are based on the Canada Income Tax Act and the BC Income Tax Act enacted legislation and are updated each year as part of the annual rate setting process.

Income tax for 2023 is forecast to decrease by $1.494 million or 19.9 percent compared to 2022 Approved. The 2023 Forecast decrease is primarily due to higher deductible temporary differences associated with amortization of deferred charges and property, plant and equipment, and lower taxable temporary differences associated with pension and OPEB, partially offset by higher rate base.

Any tax rate variances and variances in income taxes on items that are flowed through in rates are subject to flow-through treatment.

All other differences in income tax expense are subject to earnings sharing.

9.4 *SUMMARY*

FBC has forecast its property and income taxes on a basis consistent with prior years, utilizing enacted legislation for income taxes and forecast changes for property tax rates and assessments.

10. EARNINGS SHARING

In the MRP Decision (at page 82), the BCUC approved an earnings sharing mechanism from 2020 to 2024 whereby 50 percent of the achieved ROE above or below the allowed ROE will be shared with customers. Since FBC is unable to determine final earnings sharing until all items required for the ROE calculation are known, including the final rate base, there is a lag in when FBC distributes earnings sharing amounts. This is consistent with the calculations of formula O&M, where the true-up of the formula inputs happens only once actuals are known. Thus, for 2023 rates, it is the 2021 formula O&M and 2021 earnings sharing amounts that are calculated and impact rates in 2023.

For 2023, FBC proposes to distribute a $0.911 million pre-tax credit ($0.665 million after-tax) to customers, comprised of:

- The $0.665 million credit difference between the projected 2021 deferral account after-tax credit addition of zero embedded in 2022 rates, and the actual 2021 deferral account after-tax credit addition of $0.665 million as provided in FBC's 2021 Annual Report to the BCUC. This amount is also shown in the opening 2023 balance[58] in the financial schedules in the Application.

FBC proposes to distribute $0.911 million to customers in 2023 as a reduction in 2023 revenue requirements through amortization of the projected 2023 opening after-tax balance of $0.665 million in the MRP Earnings Sharing deferral account.

As part of future rate filings, the actual earnings sharing for 2022 will be distributed to or collected from customers in a similar manner as described above, which will account for the actual 2022 ROE variance from approved.

[58] Section 11, Schedule 12.2, Line 14, Column 2.

11. FINANCIAL SCHEDULES

Description	Schedule Reference
Summary Of Rate Change	1
Rate Base	
Utility Rate Base	2
Formula Inflation Factors	3
Capital Expenditures	4
Capital Expenditures To Plant Reconciliation	5
Plant In Service Continuity Schedule	6
Accumulated Depreciation Continuity Schedule	7
Schedule Not Applicable	8
Contributions In Aid Of Construction Continuity Schedule	9
Schedule Not Applicable	10
Unamortized Deferred Charges And Amortization - Rate Base	11
Unamortized Deferred Charges And Amortization - Non-Rate Base	12
Working Capital Allowance	13
Cash Working Capital	14
Schedule Not Applicable	15
Revenue Requirement	
Utility Income And Earned Return	16
Volume And Revenue	17
Revenue At Existing And Revised Rates	18
Cost Of Energy	19
Operating And Maintenance Expense	20
Depreciation And Amortization Expense	21
Property And Sundry Taxes	22
Other Revenue	23
Income Taxes	24
Capital Cost Allowance	25
Return On Capital	26
Embedded Cost Of Long Term Debt	27

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SUMMARY OF RATE CHANGE Schedule 1
FOR THE YEAR ENDING DECEMBER 31, 2023
($millions)

Line No.	Particulars	2023 Forecast		Cross Reference
	(1)	(2)	(3)	(4)
1	**VOLUME/REVENUE RELATED**			
2	Customer Growth and Volume	$ (12.546)		
3	Change in Other Revenue	(0.409)	(12.955)	
4				
5	**POWER SUPPLY**			
6	Power Purchases	19.796		
7	Wheeling	0.894		
8	Water Fees	(0.415)	20.275	
9				
10	**O&M CHANGES**			
11	Gross O&M Change	4.757		
12	Capitalized Overhead Change	(0.741)	4.016	
13				
14	**DEPRECIATION EXPENSE**			
15	Depreciation from Net Additions		2.752	
16				
17	**AMORTIZATION EXPENSE**			
18	CIAC from Net Additions	(0.210)		
19	Deferrals	(4.835)	(5.045)	
20				
21	**FINANCING AND RETURN ON EQUITY**			
22	Financing Rate Changes	3.688		
23	Financing Ratio Changes	(1.049)		
24	Rate Base Growth	5.809	8.448	
25				
26	**TAX EXPENSE**			
27	Property and Other Taxes	0.371		
28	Other Income Taxes Changes	(1.494)	(1.123)	
29				
30	**REVENUE DEFICIENCY (SURPLUS)**		**$ 16.368**	Schedule 16, Line 6, Column 4
31				
32	Revenue at Existing Rates		409.840	Schedule 18, Line 7, Column 3
33	Rate Change		3.99%	

FORTISBC INC.

Schedule 2

UTILITY RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Particulars	2022 Approved	2023 at Revised Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	Plant in Service, Beginning	$ 2,279,658	$ 2,375,297	$ 95,639	Schedule 6.1, Line 32, Column 3
2	Opening Balance Adjustment	4,512	-	(4,512)	Schedule 6.1, Line 32, Column 4
3	Net Additions	105,010	134,666	29,656	Schedule 6.1, Line 32, Column 5+6+7
4	Plant in Service, Ending	2,389,180	2,509,963	120,783	
5					
6	Accumulated Depreciation Beginning	$ (659,517)	$ (693,759)	$ (34,242)	Schedule 7.1, Line 32, Column 5
7	Opening Balance Adjustment	(569)	-	569	Schedule 7.1, Line 32, Column 6
8	Net Additions	(33,657)	(47,865)	(14,208)	Schedule 7.1, Line 32, Column 7+8+9
9	Accumulated Depreciation Ending	(693,743)	(741,624)	(47,881)	
10					
11	CIAC, Beginning	$ (232,291)	$ (243,101)	$ (10,810)	Schedule 9, Line 3, Column 2
12	Opening Balance Adjustment	(2,523)	-	2,523	
13	Net Additions	(11,712)	(11,628)	84	Schedule 9, Line 3, Column 5+6
14	CIAC, Ending	(246,526)	(254,729)	(8,203)	
15					
16	Accumulated Amortization Beginning - CIAC	$ 84,284	$ 89,140	$ 4,856	Schedule 9, Line 7, Column 2
17	Opening Balance Adjustment	212	-	(212)	
18	Net Additions	4,857	5,067	210	Schedule 9, Line 7, Column 5+6
19	Accumulated Amortization Ending - CIAC	89,353	94,207	4,854	
20					
21	Net Plant in Service, Mid-Year	$ 1,506,015	$ 1,567,697	$ 61,682	
22					
23	Adjustment for timing of Capital additions	$ 16,181	$ 22,720	$ 6,539	
24	Capital Work in Progress, No AFUDC	19,332	34,306	14,974	
25	Unamortized Deferred Charges	30,372	40,045	9,673	Schedule 11, Line 26, Column 8
26	Working Capital	6,258	6,100	(158)	Schedule 13, Line 9, Column 3
27	Utility Plant Acquisition Adjustment	4,749	4,563	(186)	
28					
29	Mid-Year Utility Rate Base	$ 1,582,907	$ 1,675,431	$ 92,524	

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Schedule 3

FORMULA INFLATION FACTORS
FOR THE YEARS ENDING DECEMBER 31, 2020 to 2023
($000s)

Line No.	Particulars	Reference	2020	2021	2022	2023	Total for 2023 Rate Setting	Cross Ref
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**Formula Cost Drivers**							
2	CPI		2.692%	1.596%	1.281%	4.940%		
3	AWE		2.881%	5.745%	6.455%	4.235%		
4	Labour Split							
5	Non Labour		38.000%	38.000%	37.000%	40.000%		
6	Labour		62.000%	62.000%	63.000%	60.000%		
7	CPI/AWE	(Line 2 x Line 5) + (Line 3 x Line 6)	2.809%	4.168%	4.541%	4.517%		
8	Productivity Factor	G-166-20	-0.500%	-0.500%	-0.500%	-0.500%		
9	Net Inflation Factor	Line 7 + Line 8	2.309%	3.668%	4.041%	4.017%		
10								
11								
12	**Growth in Average Customer Calculation**							
13	Actual/Projected Prior Year Average Customers		139,916	142,321	144,877	147,417		
14	Average Customers for the Year	Schedule 18, Line 7, Column 6	142,321	144,877	147,417	150,563		
15	Change in Average Customers	Line 14 - Line 13	2,405	2,556	2,541	3,145	10,647	
16								
17	Customer Growth Factor Multiplier	G-166-20					75%	
18	Change in Average Customers for Rate Setting Purposes	Line 15 x Line 17					7,985	
19								
20	Average Customers Used to Determine Starting UCOM	Line 13 Year 2020					139,916	
21								
22	Average Customer Forecast - 2023 Rate Setting Purposes	Line 18 + Line 20					147,901	

FORTISBC INC.

FBC Annual Review for 2023 Rates - August 5, 2022

Section 11

Schedule 4

CAPITAL EXPENDITURES
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Particulars	Total CapEx	Cross Reference
	(1)	(2)	(3)
1	**Forecast Capital Expenditures**		
2	Growth Capital	$ 30,973	
3	Sustainment Capital	45,797	
4	Other Capital	17,658	
5	Total Forecast Capital	$ 94,428	
6			
7	**Flow-Through Capital Expenditures**		
8	MRS Capital	$ -	
9	EV Charging Stations	248	
10	Total Flow-Through Capital	$ 248	
11			
12	**Total Regular Capital Expenditures**	$ 94,676	

CAPITAL EXPENDITURES TO PLANT RECONCILIATION
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Schedule 5

Line No.	Particulars	2023 Formula		Cross Reference
	(1)	(2)		(3)
1	**CAPEX**			
2	Forecast Capital Expenditures	$	94,428	
3	Flow-Through Capital		248	
4	Total Regular Capital Expenditures	$	94,676	Schedule 4, Column 2, Line 12
5				
6	**Special Projects and CPCN's**			
7	Kelowna Bulk Transformer Capacity Addition	$	1,710	
8	Total Special Projects and CPCN's	$	1,710	
9				
10	**Total Capital Expenditures**	$	96,386	
11				
12				
13	**RECONCILIATION OF CAPITAL EXPENDITURES TO PLANT**			
14				
15	Regular Capital Expenditures	$	94,676	Line 4
16	Add - Capitalized Overheads		10,918	Schedule 20, Column 4, Line 23
17	Add - AFUDC		243	
18	Gross Capital Expenditures		105,837	
19	Change in Work in Progress		-	
20	**Total Regular Additions to Plant**	$	105,837	
21				
22	Special Projects and CPCN's Capital Expenditures	$	1,710	Line 8
23	Add - AFUDC		49	
24	Gross Capital Expenditures		1,759	
25	Change in Work in Progress		43,680	
26	**Total Special Projects and CPCN Additions to Plant**	$	45,439	
27				
28	**Grand Total Additions to Plant**	$	151,276	Schedule 6.1, Columns 5 + 6, Line 32

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PLANT IN SERVICE CONTINUITY SCHEDULE Schedule 6
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Account	Particulars	12/31/2022	Opening Bal Adjustment	CPCN's	Additions	Retirements	12/31/2023	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1		**Hydraulic Production Plant**							
2	330	Land Rights	$ 962	$ -	$ -	$ -	$ -	$ 962	
3	331	Structures and Improvements	22,045	-	-	167	(12)	22,200	
4	332	Reservoirs, Dams & Waterways	119,076	-	16,151	7,747	(782)	142,192	
5	333	Water Wheels, Turbines and Gen.	105,453	-	2	699	(142)	106,012	
6	334	Accessory Equipment	51,357	-	-	128	(38)	51,447	
7	335	Other Power Plant Equipment	48,572	-	-	5	(1)	48,576	
8	336	Roads, Railroads and Bridges	1,287	-	-	-	-	1,287	
9			$ 348,752	$ -	$ 16,153	$ 8,746	$ (975)	$ 372,676	
10									
11		**Transmission Plant**							
12	350	Land Rights-R/W	$ 10,767	$ -	$ -	$ 118	$ -	$ 10,885	
13	350.1	Land Rights-Clearing	9,992	-	-	118	-	10,110	
14	353	Station Equipment	243,150	-	21,250	3,446	(305)	267,541	
15	355	Poles Towers & Fixtures	127,975	-	-	6,450	(291)	134,134	
16	356	Conductors and Devices	123,228	-	-	6,449	(313)	129,364	
17	359	Roads and Trails	959	-	-	-	-	959	
18			$ 516,071	$ -	$ 21,250	$ 16,581	$ (909)	$ 552,993	

FORTISBC INC.

PLANT IN SERVICE CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Schedule 6.1

Line No.	Account	Particulars	12/31/2022	Opening Bal Adjustment	CPCN's	Additions	Retirements	12/31/2023	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1		**Distribution Plant**							
2	360	Land Rights-R/W	$ 7,185	$ -	$ -	$ 817	$ -	$ 8,002	
3	360.1	Land Rights-Clearing	11,630	-	-	374	-	12,004	
4	362	Station Equipment	304,310	-	8,036	13,065	(885)	324,526	
5	364	Poles Towers & Fixtures	258,898	-	-	13,410	(570)	271,738	
6	365	Conductors and Devices	436,812	-	-	20,531	(728)	456,615	
7	368	Line Transformers	193,494	-	-	14,165	(1,815)	205,844	
8	369	Services	9,521	-	-	-	-	9,521	
9	370.1	AMI Meters	41,459	-	-	532	-	41,991	
10	371	Installation on Customers' Premises	938	-	-	-	-	938	
11	373	Street Lighting and Signal System	14,178	-	-	170	(42)	14,306	
12	372	EV Stations Kiosks & Charger Connectors	5,993	-	-	-	-	5,993	
13			$ 1,284,418	$ -	$ 8,036	$ 63,064	$ (4,040)	$ 1,351,478	
14									
15		**General Plant**							
16	389	Land	$ 11,184	$ -	$ -	$ -	$ -	$ 11,184	
17	390.1	Structures - Masonry	48,652	-	-	2,785	(319)	51,118	
18	390.2	Operation Building	19,432	-	-	609	(23)	20,018	
19	390.1	Leasehold Improvements	2,872	-	-	-	-	2,872	
20	391	Office Furniture & Equipment	5,399	-	-	215	(237)	5,377	
21	391.1	Computer Hardware	13,614	-	-	3,330	(3,016)	13,928	
22	391.2	Computer Software	41,906	-	-	7,033	(4,015)	44,924	
23	391.2	AMI Software	13,439	-	-	(3)	-	13,436	
24	392.1	Light Duty Vehicles	5,967	-	-	549	(484)	6,032	
25	392.1	Heavy Duty Vehciles	28,678	-	-	1,523	(351)	29,850	
26	394	Tools and Work Equipment	8,507	-	-	724	(587)	8,644	
27	397	Communication Structures & Equipment	15,707	-	-	681	(1,456)	14,932	
28	397.1	Fibre	5,729	-	-	-	(198)	5,531	
29	397.2	AMI Communications Structure & Equipment	4,970	-	-	-	-	4,970	
30			$ 226,056	$ -	$ -	$ 17,446	$ (10,686)	$ 232,816	
31									
32		**Total Plant in Service**	$ 2,375,297	$ -	$ 45,439	$ 105,837	$ (16,610)	$ 2,509,963	
33									
34		Cross Reference			Schedule 5, Line 26, Column 2	Schedule 5, Line 20, Column 2			

FORTISBC INC.

ACCUMULATED DEPRECIATION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Schedule 7

Line No.	Account	Particulars	Gross Plant for Depreciation	Depreciation Rate	12/31/2022	Opening Bal Adjustment	Depreciation Expense	Retirements	Cost of Removal	Adjustments	12/31/2023	Cross Ref
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
1		**Hydraulic Production Plant**										
2	330	Land Rights	$ 962	1.07%	$ (382)	$ -	$ 10	$ -	$ -	$ -	$ (372)	
3	331	Structures and Improvements	22,045	1.68%	5,718	-	370	(12)	-	-	6,076	
4	332	Reservoirs, Dams & Waterways	135,227	1.90%	7,278	-	2,569	(782)	(1,857)	-	7,208	
5	333	Water Wheels, Turbines and Gen.	105,455	1.79%	20,564	-	1,888	(142)	(3)	-	22,307	
6	334	Accessory Equipment	51,357	3.13%	15,121	-	1,607	(38)	(130)	-	16,560	
7	335	Other Power Plant Equipment	48,572	2.12%	20,171	-	1,030	(1)	-	-	21,200	
8	336	Roads, Railroads and Bridges	1,287	1.44%	476	-	19	-	-	-	495	
9			$ 364,905		$ 68,946	$ -	$ 7,493	$ (975)	$ (1,990)	$ -	$ 73,474	
10												
11		**Transmission Plant**										
12	350	Land Rights-R/W	$ 10,767	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
13	350.1	Land Rights-Clearing	9,992	1.27%	2,485	-	127	-	-	-	2,612	
14	353	Station Equipment	264,400	2.33%	101,920	-	6,161	(305)	(159)	-	107,617	
15	355	Poles Towers & Fixtures	127,975	2.52%	39,342	-	3,225	(291)	(469)	-	41,807	
16	356	Conductors and Devices	123,228	2.52%	24,036	-	3,105	(313)	(469)	-	26,359	
17	359	Roads and Trails	959	1.96%	432	-	19	-	-	-	451	
18			$ 537,321		$ 168,215	$ -	$ 12,637	$ (909)	$ (1,097)	$ -	$ 178,846	

FORTISBC INC.

Schedule 7.1

ACCUMULATED DEPRECIATION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Account	Particulars	Gross Plant for Depreciation	Depreciation Rate	12/31/2022	Opening Bal Adjustment	Depreciation Expense	Retirements	Cost of Removal	Adjustments	12/31/2023	Cross Ref
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
1		**Distribution Plant**										
2	360	Land Rights-R/W	$ 7,185	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
3	360.1	Land Rights-Clearing	11,630	1.25%	2,935	-	145	-	-	-	3,080	
4	362	Station Equipment	312,346	2.61%	93,321	-	8,152	(885)	(156)	-	100,432	
5	364	Poles Towers & Fixtures	258,898	2.73%	80,092	-	7,068	(570)	(567)	-	86,023	
6	365	Conductors and Devices	436,812	2.38%	129,625	-	10,396	(728)	(914)	-	138,379	
7	368	Line Transformers	193,494	3.13%	45,961	-	6,056	(1,815)	(347)	-	49,855	
8	369	Services	9,521	0.51%	6,807	-	49	-	-	-	6,856	
9	370.1	AMI Meters	41,459	6.25%	12,897	-	2,591	-	-	-	15,488	
10	371	Installation on Customers' Premises	938	0.00%	937	-	-	-	-	-	937	
11	373	Street Lighting and Signal System	14,178	4.95%	6,259	-	702	(42)	-	-	6,919	
12	372	EV Stations Kiosks & Charger Connectors	5,993	10.00%	914	-	599	-	-	-	1,513	
13			$ 1,292,454		$ 379,748	$ -	$ 35,758	$ (4,040)	$ (1,984)	$ -	$ 409,482	
14												
15		**General Plant**										
16	389	Land	$ 11,184	0.00%	$ 34	$ -	$ -	$ -	$ -	$ -	$ 34	
17	390.1	Structures - Masonry	48,652	2.53%	13,006	-	1,231	(319)	-	-	13,918	
18	390.2	Operation Building	19,432	1.63%	7,081	-	317	(23)	-	-	7,375	
19	390.1	Leasehold Improvements	2,872	1.63%	2,700	-	47	-	-	-	2,747	
20	391	Office Furniture & Equipment	5,399	4.42%	1,501	-	239	(237)	-	-	1,503	
21	391.1	Computer Hardware	13,614	21.60%	4,496	-	2,941	(3,016)	-	-	4,421	
22	391.2	Computer Software	41,906	8.96%	16,368	-	3,755	(4,015)	-	-	16,108	
23	391.2	AMI Software	13,439	10.00%	7,627	-	1,344	-	-	-	8,971	
24	392.1	Light Duty Vehicles	5,967	3.81%	2,528	-	227	(484)	77	-	2,348	
25	392.1	Heavy Duty Vehciles	28,678	6.50%	8,066	-	1,864	(351)	-	-	9,579	
26	394	Tools and Work Equipment	8,507	4.11%	3,500	-	350	(587)	-	-	3,263	
27	397	Communication Structures & Equipment	15,707	3.44%	5,067	-	540	(1,456)	(5)	-	4,146	
28	397.1	Fibre	5,729	6.97%	2,486	-	399	(198)	-	-	2,687	
29	397.2	AMI Communications Structure & Equipment	4,970	6.67%	2,390	-	332	-	-	-	2,722	
30			$ 226,056		$ 76,850	$ -	$ 13,586	$ (10,686)	$ 72	$ -	$ 79,822	
31												
32		**Total**	$ 2,420,736		$ 693,759	$ -	$ 69,474	$ (16,610)	$ (4,999)	$ -	$ 741,624	
33												
34		Cross Reference	Schedule 6.1, Line 32, Column 3+4+5									

SCHEDULE NOT APPLICABLE

FORTISBC INC. FBC Annual Review for 2023 Rates - August 5, 2022 Section 11

Schedule 9

CONTRIBUTIONS IN AID OF CONSTRUCTION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Particulars	12/31/2022	CPCN / Open Bal Adjt	Adjustment	Additions	Retirements	12/31/2023	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**CIAC**							
2	CIAC	$ 243,101	$ -	$ -	$ 11,628	$ -	$ 254,729	
3	**Total**	$ 243,101	$ -	$ -	$ 11,628	$ -	$ 254,729	
4								
5	**Amortization**							
6	Amortization	$ (89,140)	$ -	$ -	$ (5,067)	$ -	$ (94,207)	
7	**Total**	$ (89,140)	$ -	$ -	$ (5,067)	$ -	$ (94,207)	
8								
9	**Net CIAC**	$ 153,961	$ -	$ -	$ 6,561	$ -	$ 160,522	

SCHEDULE NOT APPLICABLE

FORTISBC INC. FBC Annual Review for 2023 Rates - August 5, 2022 Section 11

Schedule 11

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Particulars	12/31/2022	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	12/31/2023	Mid-Year Average	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**1. Forecasting Variance Accounts**								
2	BCUC Levies Variance Account	$ 32	$ -	$ -	$ -	$ (32)	$ -	$ 16	
3									
4	**2. Rate Smoothing Accounts**								
5									
6	**3. Benefits Matching Accounts**								
7	Preliminary and Investigative Charges	$ 2,646	$ -	$ (439)	$ -	$ -	$ 2,207	$ 2,427	Note 1
8	Demand Side Management	37,219	-	14,455	(3,903)	(5,829)	41,942	39,581	
9	Deferred Debt Issue Costs	4,074	-	600	(111)	(167)	4,396	4,235	
10	Joint Pole Use Audit 2023	-	-	435	(117)	(64)	254	127	
11	2021 Generic Cost of Capital Proceeding	675	-	450	(122)	-	1,003	839	
12	Annual Reviews for 2020-2024 Rates	154	-	200	(54)	(154)	146	150	
13	2021 Long Term Electric Resource Plan	264	-	250	(68)	(113)	333	298	
14	BCUC Initiated Inquiry Costs	109	-	100	(27)	(109)	73	91	
15	Mandatory Reliability Standards 2021 Audit	157	-	-	-	(79)	78	118	
16		$ 45,298	$ -	$ 16,051	$ (4,402)	$ (6,515)	$ 50,432	$ 47,866	
17									
18	**4. Retroactive Expense Accounts**								
19									
20	**5.Other Accounts**								
21	Pension and OPEB Liability	$ (10,592)	$ -	$ 4,664	$ -	$ -	$ (5,928)	$ (8,260)	
22	COVID-19 Customer Recovery Fund	507	-	-	-	(169)	338	423	
23	Indigenous Relations Agreement (Huth Substation)	-	-	-	-	-	-	-	
24		$ (10,085)	$ -	$ 4,664	$ -	$ (169)	$ (5,590)	$ (7,837)	
25									
26	**Total Rate Base Deferral Accounts**	$ 35,245	$ -	$ 20,715	$ (4,402)	$ (6,716)	$ 44,842	$ 40,045	
27									

28 Note 1: Gross Additions for Preliminary and Investigative Charges are after transfers to Construction Work in Progress. Additions of $0.851 million - transfer of $1.290 million = $(0.439) million.

FORTISBC INC. FBC Annual Review for 2023 Rates - August 5, 2022 Section 11

Schedule 12

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - NON-RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Particulars	12/31/2022	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	12/31/2023	Mid-Year Average	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**Deferral Accounts Financed at Short Term Interest Rate**								
2									
3	**1. Forecasting Variance Accounts**								
4	Pension & Other Post Retirement Benefits (OPEB) Variance	$ 1,493	$ -	$ -	$ -	$ (604)	$ 889	$ 1,191	
5									
6	**2. Rate Smoothing Accounts**								
7									
8	**3. Benefits Matching Accounts**								
9	Tariff Applications	31	-	-	-	(31)	-	15	
10		$ 31	$ -	$ -	$ -	$ (31)	$ -	$ 15	
11									
12	**4. Retroactive Expense Accounts**								
13									
14	**5.Other Accounts**								
15									
16	**Total NRB Deferral Accounts at Short Term Interest**	$ 1,524	$ -	$ -	$ -	$ (635)	$ 889	$ 1,206	
17									
18	Financing Costs at STI	$ 8	$ -	$ 37	$ -	$ (8)	$ 37	$ 23	

FORTISBC INC.

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - NON-RATE BASE cont'd
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Particulars	12/31/2022	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	12/31/2023	Mid-Year Average	Cross Ref
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**Deferral Accounts Financed at Weighted Average Cost of Debt**								
2									
3	**1. Forecasting Variance Accounts**								
4									
5	**2. Rate Smoothing Accounts**								
6									
7	**3. Benefits Matching Accounts**								
8	CPCN Projects Preliminary Engineering [1]	$ 980	$ -	$ 450	$ -	$ -	$ 1,430	$ 1,205	
9	2017 Rate Design Application	236	-	-	-	(118)	118	177	
10	2020 - 2024 Multi-Year Rate Plan Application	290	-	-	-	(145)	145	217	
11	Rate Design and Rates for Electric Vehicle Direct Current Fast Charging Service Application	127	-	-	-	(59)	68	98	
12		$ 1,633	$ -	$ 450	$ -	$ (322)	$ 1,761	$ 1,697	
13									
14	**4. Retroactive Expense Accounts**								
15									
16	**5.Other Accounts**								
17	US GAAP Pension and OPEB Transition Obligation	$ 348	$ -	$ (348)	$ -	$ -	$ -	$ 174	
18	Advanced Metering Infrastructure Radio-Off Shortfall	25	-	-	-	(25)	-	12	
19		$ 373	$ -	$ (348)	$ -	$ (25)	$ -	$ 186	
20									
21	**Total NRB Deferral Accounts at Weighted Average Cost of Debt**	$ 2,006	$ -	$ 102	$ -	$ (347)	$ 1,761	$ 1,883	
22									
23	Financing Costs at WACD	$ 64	$ -	$ 66	$ -	$ (64)	$ 66	$ 65	

24 Note 1: Gross additions for CPCN Projects Preliminary Engineering after transfers to Construction Work in Progress.

FORTISBC INC.

Schedule 12.2

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - NON-RATE BASE cont'd
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Particulars	12/31/2022	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	12/31/2023	Mid-Year Average	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**Deferral Accounts Financed at Weighted Average Cost of Capital**								
2									
3	**1. Forecasting Variance Accounts**								
4	2020 - 2024 Flow-Through Deferral Account	$ (9,625)	$ -	$ -	$ -	$ 9,625	$ -	$ (4,813)	
5									
6	**2. Rate Smoothing Accounts**								
7									
8	**3. Benefits Matching Accounts**								
9	On Bill Financing (OBF) Participant Loans	$ 1	$ -	$ (1)	$ -	$ -	$ -	$ 1	
10									
11	**4. Retroactive Expense Accounts**								
12									
13	**5.Other Accounts**								
14	MRP Earnings Sharing Account	$ (665)	$ -	$ -	$ -	$ 665	$ -	$ (333)	
15									
16	**Total NRB Deferral Accounts at Weighted Average Cost of Capital**	$ (10,289)	$ -	$ (1)	$ -	$ 10,290	$ -	$ (5,145)	
17									
18	Financing Costs at AFUDC	$ (757)	$ -	$ (317)	$ -	$ 757	(317)	(537)	
19									
20	**Non Rate Base Deferral Accounts Non-Interest Bearing**	$ 50	$ -	$ -	$ -	$ -	$ 50	$ 50	
21									
22									
23	**Total Non Rate Base Deferral Accounts (including financing)**	**$ (7,394)**	**$ -**	**$ (113)**	**$ -**	**$ 9,993**	**$ 2,487**	**$ (2,455)**	

FORTISBC INC.

FBC Annual Review for 2023 Rates - August 5, 2022

Section 11

Schedule 13

WORKING CAPITAL ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Particulars	2022 Approved	2023 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Cash Working Capital**				
2	Cash Working Capital	$ 7,065	$ 6,850	$ (215)	Schedule 14, Line 32, Column 5
3					
4	Add/Less: Funds Unavailable/(Funds Available)				
5	Customers Loans	329	353	24	
6	Employee Loans	443	570	127	
7	Inventories - Materials and Supplies	612	649	37	
8	Employee Withholdings	(2,191)	(2,322)	(131)	
9	Total	$ 6,258	$ 6,100	$ (158)	

FORTISBC INC. FBC Annual Review for 2023 Rates - August 5, 2022 Section 11

Schedule 14

CASH WORKING CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Particulars	2023 at Revised Rates	Lag (Lead) Days	Extended	Weighted Average Lag (Lead) Days	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)
1	**REVENUE**					
2	**Sales Revenue**					
3	Residential Tariff Revenue	$ 205,868	56.0	$ 11,528,608		
4	Commercial Tariff Revenue	110,473	45.1	4,982,332		
5	Wholesale Tariff Revenue	54,109	37.5	2,029,088		
6	Industrial Tariff Revenue	49,767	38.0	1,891,146		
7	Lighting Tariff Revenue	2,295	34.6	79,407		
8	Irrigation Tariff Revenue	3,696	47.0	173,712		
9						
10	**Other Revenue**					
11	Apparatus and Facilities Rental	$ 6,108	90.0	$ 549,720		
12	Contract Revenue	2,367	62.2	147,227		
13	Transmission Access Revenue	1,834	65.2	119,577		
14	Late Payment Charges	994	54.0	53,658		
15	Connection Charges	553	30.5	16,867		
16	Other Utility Income	385	63.4	24,409		
17	Total	$ 438,449		$ 21,595,751		49.3
18						
19	**EXPENSES**					
20	Power Purchases	$ 163,575	(51.5)	$ (8,424,126)		
21	Wheeling	6,987	(46.9)	(327,699)		
22	Water Fees	11,543	(1.4)	(16,160)		
23	Operating and Maintenance	61,871	(28.6)	(1,769,501)		
24	Property Taxes	18,260	(4.9)	(89,474)		
25	GST	593	(45.4)	(26,900)		
26	Income Tax	6,005	(15.2)	(91,276)		
27	Total	$ 268,833		$ (10,745,136)		(40.0)
28						
29	Net Lag (Lead) Days					9.3
30	Total Expenses				$	268,833
31						
32	Cash Working Capital				$	6,850

SCHEDULE NOT APPLICABLE

FORTISBC INC. FBC Annual Review for 2023 Rates - August 5, 2022 Section 11

Schedule 16

UTILITY INCOME AND EARNED RETURN
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Particulars	2022 Approved	2023 Forecast at 2022 Approved Rates	2023 Forecast Revised Revenue	2023 Forecast at Revised Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**ENERGY VOLUMES**						
2	Sales Volume (GWh)	3,306	3,476	-	3,476	170	Schedule 17, Line 8, Column 3
3							
4	**REVENUE**						
5	Sales	$ 397,294	$ 409,840	$ -	$ 409,840	$ 12,546	Schedule 17, Line 17, Column 3
6	Deficiency (Surplus)	-	-	16,368	16,368	16,368	
7	Total	397,294	409,840	16,368	426,208	28,914	Schedule 18, Line 7, Column 5
8							
9	**EXPENSES**						
10	Cost of Energy	$ 161,830	$ 182,105	$ -	$ 182,105	$ 20,275	Schedule 19, Line 30, Column 3
11	O&M Expense (net)	57,855	61,871	-	61,871	4,016	Schedule 20, Line 24, Column 4
12	Depreciation & Amortization	63,609	61,316	-	61,316	(2,293)	Schedule 21, Line 11, Column 3
13	Property Taxes	17,889	18,260	-	18,260	371	Schedule 22, Line 6, Column 3
14	Other Revenue	(11,832)	(12,241)	-	(12,241)	(409)	Schedule 23, Line 9, Column 3
15	Utility Income Before Income Taxes	107,943	98,529	16,368	114,897	6,954	
16							
17	Income Taxes	7,499	1,589	4,416	6,005	(1,494)	Schedule 24, Line 13, Column 3
18							
19	**EARNED RETURN**	$ 100,444	$ 96,940	$ 11,952	$ 108,892	$ 8,448	Schedule 26, Line 5, Column 7
20							
21	**UTILITY RATE BASE**	$ 1,582,907	$ 1,675,028		$ 1,675,431	$ 92,524	Schedule 2, Line 29, Column 3
22	**RATE OF RETURN ON UTILITY RATE BASE**	6.35%	5.79%		6.50%	0.15%	Schedule 26, Line 5, Column 6

FORTISBC INC. FBC Annual Review for 2023 Rates - August 5, 2022 Section 11

Schedule 17

VOLUME AND REVENUE
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Particulars	2022 Approved	2023 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**ENERGY VOLUME SOLD (GWh)**				
2	Residential	1,283	1,301	18	
3	Commercial	946	973	27	
4	Wholesale	560	578	18	
5	Industrial	470	575	105	
6	Lighting	10	9	(1)	
7	Irrigation	37	39	2	
8	Total	3,306	3,476	170	
9					
10	**REVENUE AT EXISTING RATES**				
11	Residential	$ 195,058	$ 197,962	$ 2,904	
12	Commercial	104,380	106,230	1,850	
13	Wholesale	51,255	52,031	776	
14	Industrial	40,804	47,856	7,052	
15	Lighting	2,411	2,207	(204)	
16	Irrigation	3,386	3,554	168	
17	Total	$ 397,294	$ 409,840	$ 12,546	

FORTISBC INC. FBC Annual Review for 2023 Rates - August 5, 2022 Section 11

REVENUE AT EXISTING AND REVISED RATES
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Schedule 18

Line No.	Particulars	2022 Approved Revenue	2023 Forecast Revenue at 2022 Approved Rates	2023 Forecast Effective Increase	2023 Forecast Revenue at Revised Rates	Average Number of Customers	GWh	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	Residential	$ 195,058	$ 197,962	$ 7,906	$ 205,868	130,787	1,301	
2	Commercial	104,380	106,230	4,243	110,473	17,267	973	
3	Wholesale	51,255	52,031	2,078	54,109	6	578	
4	Industrial	40,804	47,856	1,911	49,767	42	575	
5	Lighting	2,411	2,207	88	2,295	1,358	9	
6	Irrigation	3,386	3,554	142	3,696	1,103	39	
7	Total	$ 397,294	$ 409,840	$ 16,368	$ 426,208	150,563	3,476	
8								
9	**Effective Increase**			3.99%				

FORTISBC INC. FBC Annual Review for 2023 Rates - August 5, 2022 Section 11

COST OF ENERGY Schedule 19
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Particulars	2022 Approved	2023 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**POWER PURCHASES**				
2	Gross Load (GWh)	3,591	3,775	184	
3					
4	**Power Purchase Expense**				
5	Brilliant	$ 41,841	$ 44,050	$ 2,209	
6	BC Hydro PPA	44,062	71,302	27,240	
7	Waneta Expansion	42,701	41,834	(867)	
8	Market and Contracted Producers	15,102	6,326	(8,776)	
9	Independent Power Producers	73	62	(11)	
10	Self-Generators	-	-	-	
11	CPA Balancing Pool	-	-	-	
12	Total	$ 143,779	$ 163,575	$ 19,796	
13					
14	**WHEELING**				
15	**Wheeling Nomination (MW months)**				
16	Okanagan Point of Interconnection	2,475	2,670	195	
17	Creston	420	420	-	
18					
19	**Wheeling Expense**				
20	Okanagan Point of Interconnect	$ 4,903	$ 5,555	$ 652	
21	Creston	542	570	28	
22	Other	648	863	215	
23	Total	$ 6,093	$ 6,987	$ 894	
24					
25	**WATER FEES**				
26	Plant Entitlement Use in previous year (GWh)	1,679	1,571	(108)	
27					
28	Water Fees	$ 11,958	$ 11,543	$ (415)	
29					
30	Total	$ 161,830	$ 182,105	$ 20,275	

FORTISBC INC. FBC Annual Review for 2023 Rates - August 5, 2022 Section 11

OPERATING AND MAINTENANCE EXPENSE
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Schedule 20

Line No.	Particulars	Inflation Indexed O&M	Forecast O&M	Total O&M	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Inflation Indexed O&M**				
2	2022 Base Unit Cost O&M	$ 455			
3	2023 Net Inflation Factor	4.017%			Schedule 3, Line 9, Column 6
4	2023 Base Unit Cost O&M	$ 473			Line 2 x (1 + Line 3)
5					
6	2023 Average Customer Forecast - Rate Setting Purpose	147,901			Schedule 3, Line 22, Column 7
7					
8	2023 Inflation Indexed O&M before prior year True-up	$ 69,957			Line 4 x Line 6 / 1,000
9					
10	2021 Average Customer True-up	509			
11					
12	2023 Inflation Indexed O&M	$ 70,466		$ 70,466	Sum of Lines 8 and 10
13					
14	**O&M Tracked Outside of Formula**				
15	Pension & OPEB (O&M Portion)		$ (1,297)		
16	Insurance Premiums		2,457		
17	BCUC Levies		385		
18	MRS		585		
19	EV Charging Stations		193		
20	Sub-total		$ 2,323	2,323	Sum of Lines 15 through 19
21					
22	**Total Gross O&M**			$ 72,789	Line 12 + Line 20
23	Capitalized Overhead			(10,918)	-15 % x Line 22
24	**Net O&M Expense**			$ 61,871	Sum of Lines 22 and 23

DEPRECIATION AND AMORTIZATION EXPENSE
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Particulars	2022 Approved	2023 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Depreciation**				
2	Depreciation Expense	$ 66,722	$ 69,474	$ 2,752	Schedule 7.1, Line 32, Column 7
3					
4	**Amortization**				
5	Rate Base Deferrals	$ 5,913	$ 6,716	$ 803	Schedule 11, Line 26, Column 6
6	Non-Rate Base Deferrals	(4,355)	(9,993)	(5,638)	Schedule 12.2, Line 23, Column 6
7	Utility Plant Acquisition Adjustment	186	186	-	
8	CIAC	(4,857)	(5,067)	(210)	Schedule 9, Line 7, Column 5
9		(3,113)	(8,158)	(5,045)	
10					
11	Total	$ 63,609	$ 61,316	$ (2,293)	

FORTISBC INC.

FBC Annual Review for 2023 Rates - August 5, 2022

Section 11

Schedule 22

PROPERTY AND SUNDRY TAXES
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Particulars	2022 Approved	2023 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	Generating Plant	$ 3,210	$ 3,253	$ 43	
2	Transmission and Distribution	7,428	7,189	(239)	
3	Substation Equipment	3,948	4,208	260	
4	Land and Buildings	1,165	1,322	157	
5	1% In-Lieu of Municipal Taxes	2,138	2,288	150	
6	Total	$ 17,889	$ 18,260	$ 371	

OTHER REVENUE
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Particulars	2022 Approved	2023 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	Apparatus and Facilities Rental	$ 6,018	$ 6,108	$ 90	
2	Contract Revenue	2,277	2,367	90	
3	Transmission Access Revenue	1,771	1,834	63	
4	Interest Income	20	30	10	
5	Late Payment Charges	875	994	119	
6	Connection Charges	505	553	48	
7	Other Recoveries	366	355	(11)	
8	EV Carbon Credits	-	-	-	
9	Total	$ 11,832	$ 12,241	$ 409	

FORTISBC INC.

FBC Annual Review for 2023 Rates - August 5, 2022

Section 11

Schedule 24

INCOME TAXES
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Particulars	2022 Approved	2023 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**EARNED RETURN**	$ 100,444	$ 108,892	$ 8,448	Schedule 16, Line 19, Column 5
2	Deduct: Interest on Debt	(42,510)	(47,571)	(5,061)	Schedule 26, Line 1+2, Column 7
3	Adjustments to Taxable Income	(37,660)	(45,084)	(7,424)	Line 32
4	Accounting Income After Tax	$ 20,274	$ 16,237	$ (4,037)	
5					
6	1 - Current Income Tax Rate	73.00%	73.00%	0.00%	
7	Taxable Income	$ 27,773	$ 22,242	$ (5,531)	
8					
9	Current Income Tax Rate	27.00%	27.00%	0.00%	
10	Income Tax - Current	$ 7,499	$ 6,005	$ (1,494)	
11					
12	Previous Year Adjustment	-	-	-	
13	**Total Income Tax**	$ 7,499	$ 6,005	$ (1,494)	
14					
15					
16	**ADJUSTMENTS TO TAXABLE INCOME**				
17	Addbacks:				
18	Depreciation	$ 66,722	$ 69,474	$ 2,752	Schedule 21, Line 2, Column 3
19	Amortization of Deferred Charges	1,558	(3,277)	(4,835)	Schedule 21, Line 5+6, Column 3
20	Amortization of Utility Plant Acquisition Adjustment	186	186	-	Schedule 21, Line 7, Column 3
21	Pension Expense	84	(528)	(612)	
22	OPEB Expense	1,607	1,119	(488)	
23					
24	Deductions:				
25	Capital Cost Allowance	(86,398)	(89,854)	(3,456)	Schedule 25, Line 19, Column 6
26	CIAC Amortization	(4,857)	(5,067)	(210)	Schedule 21, Line 8, Column 3
27	Pension Contributions	(4,419)	(4,203)	216	
28	OPEB Contributions	(655)	(705)	(50)	
29	Overheads Capitalized Expensed for Tax Purposes	(10,177)	(10,918)	(741)	Schedule 20, Line 23, Column 4
30	Removal Costs	(1,200)	(1,200)	-	
31	All Other	(111)	(111)	-	
32	Total	$ (37,660)	$ (45,084)	$ (7,424)	

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Schedule 25

CAPITAL COST ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Class	CCA Rate	12/31/2022 UCC Balance	2023 Additions & Opening Adjt	UCC Adjustment for AIIP *	2023 CCA	Forecast 12/31/2023 UCC Balance
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	1(a)	4%	$ 154,085	$ -	$ -	$ (6,163)	$ 147,922
2	1(b)	6%	33,091	3,043	1,521	(2,259)	33,875
3	2	6%	11,403	-	-	(684)	10,719
4	3	5%	648	-	-	(32)	616
5	6	10%	2	-	-	-	2
6	8	20%	3,694	842	421	(991)	3,545
7	10	30%	4,709	1,857	929	(2,250)	4,316
8	13	0%	11	-	-	-	11
9	14.1 (pre 2017)	7%	6,926	-	-	(485)	6,441
10	14.1 (post 2016)	5%	3,951	1,280	640	(294)	4,937
11	17	8%	156,652	22,036	11,018	(15,177)	163,511
12	42	12%	9,649	610	305	(1,268)	8,991
13	43.1	30%	566	(155)	-	(123)	288
14	45	45%	1	-	-	-	1
15	46	30%	2,708	-	-	(812)	1,896
16	47	8%	494,831	87,737	43,868	(50,115)	532,453
17	50	55%	2,800	9,286	4,643	(9,201)	2,885
18							
19	Total		$ 885,727	$ 126,536	$ 63,345	$ (89,854)	$ 922,409
20							
21	* Note - Accelerated Investment Incentive Property						

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Schedule 26

RETURN ON CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Particulars	2022 Approved Earned Return	Amount	Ratio	2023 Average Embedded Cost	Cost Component	Earned Return	Earned Return Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	Long Term Debt	$ 41,155	$ 914,178	54.56%	4.78%	2.61%	$ 43,709	$ 2,554	Schedule 27, Line 12, Column 6
2	Short Term Debt	1,355	91,081	5.44%	4.24%	0.23%	3,862	2,507	
3	Common Equity	57,934	670,172	40.00%	9.15%	3.66%	61,321	3,387	
4									
5	Total	$ 100,444	$ 1,675,431	100.00%		6.50%	$ 108,892	$ 8,448	
6									
7	Cross Reference		Schedule 2, Line 29, Column 3						

FORTISBC INC.

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Section 11

Schedule 27

EMBEDDED COST OF LONG TERM DEBT
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Particulars	Issue Date	Maturity Date	Average Principal Outstanding	Interest Rate	Interest Expense	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	1993 Debt Issue - Series G	August 28, 1993	August 28, 2023	$ 16,370	8.800%	$ 1,441	
2	2005 Debt Issue - Series 1 - 05	November 9, 2005	November 9, 2035	100,000	5.600%	5,600	
3	2007 Debt Issue - Series 1 - 07	July 4, 2007	July 4, 2047	105,000	5.900%	6,195	
4	2009 Debt Issue - MTN - 09	June 2, 2009	June 2, 2039	105,000	6.100%	6,405	
5	2010 Debt Issue - MTN - 10	November 24, 2010	November 24, 2050	100,000	5.000%	5,000	
6	2014 Debt Issue - MTN - 14	October 28, 2014	October 28, 2044	200,000	4.000%	8,000	
7	2017 Debt Issue - MTN - 17	December 4, 2017	December 6, 2049	75,000	3.620%	2,715	
8	2020 Debt Issue - MTN - 20	May 11, 2020	May 11, 2050	75,000	3.120%	2,340	
9	2022 Debt Issue - MTN - 22	March 14, 2022	March 14, 2052	100,000	4.160%	4,160	
10	2023 Debt Issue - MTN - 23	July 1, 2023	July 1, 2053	37,808	4.900%	1,853	
11							
12	Total			$ 914,178		$ 43,709	
13							
14	Average Embedded Cost				4.78%		

12. ACCOUNTING MATTERS

12.1 INTRODUCTION AND OVERVIEW

In this section, FBC discusses "Exogenous Factors" under its MRP, providing an update on the exogenous factor treatment for the impacts of the COVID-19 pandemic. FBC also discusses emerging accounting guidance, and the status of its non-rate base deferral accounts. With respect to its non-rate base deferral accounts, FBC provides information on the Flow-through deferral account.

12.2 EXOGENOUS (Z) FACTORS

FBC is permitted to adjust the cost of service for "Exogenous Factors" under the MRP. The BCUC established the following criteria for evaluating whether the impact of an event qualifies for exogenous factor treatment:

1. The costs/savings must be attributable entirely to events outside the control of a prudently operated utility;
2. The costs/savings must be directly related to the exogenous event and clearly outside the base upon which the rates were originally derived;
3. The impact of the event was unforeseen;
4. The costs must be prudently incurred; and
5. The costs/savings related to each exogenous event must exceed the BCUC-defined materiality threshold.

The materiality threshold (item 5) for FBC has been established at $0.150 million, as approved in the MRP Decision.

In the Annual Review for 2020 and 2021 Rates, FBC identified the COVID-19 pandemic as a potential exogenous factor affecting 2020 and future years, and the BCUC approved FBC's request to record COVID-19 pandemic incremental costs and cost reductions from 2020 and 2021 into the previously approved COVID-19 Customer Recovery Fund Deferral Account.[59] FBC also stated in the Annual Review for 2020 and 2021 Rates application that it would review the amounts in 2021 when actual 2020 amounts and forecasts for future years could be ascertained, and an appropriate recovery method could be determined. In the Annual Review for 2022 Rates application, FBC provided a status update on the COVID-19 pandemic net incremental costs (costs less cost reductions). In the following section, FBC reports on the net incremental cost reductions and proposes to return these cost reductions to customers.

[59] FBC Annual Review for 2020 and 2021 Rates Decision and Order G-42-21.

12.2.1 COVID-19 Pandemic

During the COVID-19 pandemic, FBC has taken the necessary steps as a critical infrastructure service provider to ensure the health, safety and well-being of its customers, employees and their communities, and to continue to operate its system safely and reliably. This has resulted in net incremental O&M impacts.

12.2.1.1 FBC Has Reasonably Tracked the Impact of the COVID-19 Pandemic on Net Operating Costs

Consistent with the MRP, FBC's general approach to managing its formula O&M funding is at an overall Company level. O&M funding is prioritized and allocated as required to meet the business environment, conditions and requirements the Company faces. Funding utilized for a specific purpose in one year may be used differently in the following year. As a result, this makes the determination of COVID-19 pandemic net incremental O&M costs from year to year challenging and fluid, particularly for cost reductions, as the Company reprioritizes its funding regularly to meet its needs to provide safe and reliable operations.

Further, the COVID-19 pandemic has a broad impact throughout the organization, making the determination of the incremental costs more challenging. The impact of the COVID-19 pandemic varies in different parts of the business. For example, there may be additional overtime costs in departments that are indirectly influenced by the pandemic (e.g., less internal resources available due to reassignment to assist with other priorities), which are difficult to specifically identify. Also, there may be delays in work scheduled as a result of the pandemic that may increase the total cost of the work required, which are not specifically identified as COVID-19 pandemic related.

Recognizing the above circumstances, FBC has undertaken its best efforts to track and report on the net incremental O&M costs that are directly related to the COVID-19 pandemic. FBC has included below all costs that are specifically identifiable as attributable to activities required to respond to the COVID-19 pandemic as part of the overall net incremental costs (costs less cost reductions). While acknowledging there are uncertainties, the following summary of net incremental cost reductions provides a reasonable representation of the overall COVID-19 pandemic impact on the Company.

12.2.1.2 Summary of Net Incremental Costs

The combined impact in 2020 and 2021 as a result of the COVID-19 pandemic is a decrease by approximately $1.03 million in FBC's net incremental O&M expense (costs less cost reductions).

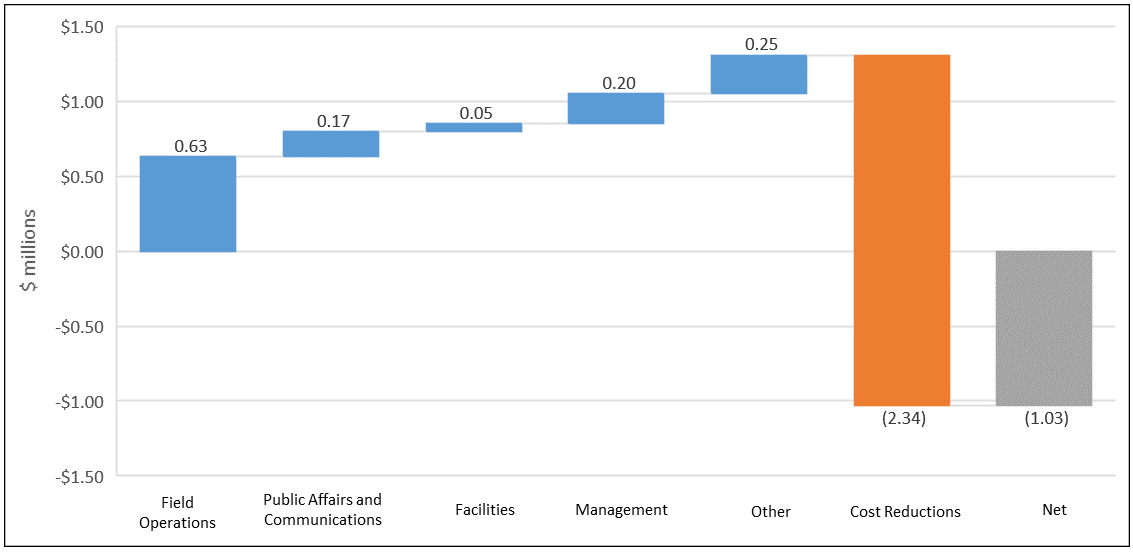
Table 12-1: Net Incremental Cost Reductions ($ millions)

	2020	2021	2020/2021
Direct Costs			
Field Operations	$ 0.46	$ 0.18	$ 0.63
Public Affairs and Communications	$ 0.16	$ 0.01	$ 0.17
Facilities	$ 0.04	$ 0.01	$ 0.05
Management	$ 0.10	$ 0.10	$ 0.20
Other	$ 0.18	$ 0.07	$ 0.25
Total Direct Costs	$ 0.94	$ 0.36	$ 1.31
Cost Reductions	$ (1.05)	$ (1.29)	$ (2.34)
Net difference	$ (0.10)	$ (0.93)	$ (1.03)

12.2.1.3 2020 and 2021 COVID-19 Pandemic Impact

While the COVID-19 pandemic increased many areas of O&M costs in 2020 and 2021, these costs were more than offset by lower employee related expenses. In 2020 and 2021, FBC incurred approximately $1.31 million in O&M costs related to the COVID-19 pandemic. These costs were primarily to ensure the health, safety and well-being of FBC's customers, employees, and their communities, and to continue to operate the system safely and reliably. The incremental costs were offset by approximately $2.34 million in employee expense related reductions. The figure below shows the categories of costs incurred and the offsetting savings. Each of the categories is described further below.

Figure 12-1: FBC COVID-19 Pandemic 2020 and 2021 Net O&M Cost Reductions



12.2.1.3.1 INCREASED O&M EXPENDITURES DUE TO THE COVID-19 PANDEMIC

In the Field Operations area, FBC incurred approximately $0.63 million related to the COVID-19 pandemic, with the majority of the costs related to the sequestering of system control centre employees from having to return to their homes and separation of the operators between the system control centre and Kootenay operating centre sites to ensure a safe and healthy work environment for this critical function. FBC also incurred costs for personal protective equipment (i.e., masks, gloves and sanitizers).

In the Public Affairs and Communications area, FBC incurred approximately $0.17 million for activities to keep customers and key stakeholders informed of the Company's assistance available during the COVID-19 pandemic, including the support required to develop the materials and to monitor and maintain messaging as needed. The costs were for advertising, various communication materials such as bill inserts, and labour and consultant services required to develop the materials and to monitor and maintain messaging as needed.

FBC incurred approximately $0.05 million for Facilities-related resources and activities including safety supplies, additional cleaning, first aid coverage, and signage.

Under the category of Management, approximately $0.20 million in management resource costs were added to support the following areas: the operation of the Emergency Operating Centre (EOC); the Human Resources and Environmental, Health and Safety groups' response to COVID-19 pandemic incidents and issues for employees and contractors; and the increased needs of supporting departments such as Information Systems, Supply Chain, Communications, and Business Continuity. The resources were necessary to respond to the COVID-19 pandemic and to address the various needs of the health authorities, regulators, and organizations like Emergency Management BC.

The Other category of approximately $0.25 million includes miscellaneous items such as different support group costs (e.g., Information Systems and TELUS Babylon health service).

12.2.1.3.2 O&M COST REDUCTIONS OFFSET INCREASED COSTS

The cost reductions that FBC achieved consist primarily of lower employee expenses, in part as a response to the travel restrictions, including in and out of Province travel, and the effect that the COVID-19 pandemic has had on social interactions. Employee expenses that were not incurred include course fees, travel, meals and accommodation, Company function expenses, and employee hiring and relocation expenses.

For the years 2020 and 2021, the reduced employee expenses were estimated at approximately $2.34 million.

12.2.1.3.3 CUMULATIVE NET IMPACT

The variances for the 2020 and 2021 net incremental O&M (costs less cost reductions) total to a net decrease of approximately $1.03 million.

Accordingly, FBC requests approval to return the exogenous factor savings of $1.03 million to customers in 2023, as further described below.

12.2.1.4 2022 COVID-19 Pandemic Impact

With the Company's transition to normal operations, FBC does not anticipate further impacts on its costs in 2022 requiring exogenous factor treatment. As mentioned in FBC's 2022 Annual Review, FBC started the transition to normal operations in September 2021 with the Province achieving Step 4 of the Province of BC Four Step Restart Plan. Step 4 included the lifting of restrictions with normal social contact allowed and workplaces fully reopened. For FBC, this meant having its employees return to offices and worksites starting September 7, 2021 with 100 percent of employees on site at least 50 percent of the time while maintaining building capacity at 50 percent.

The transition to normal operations continued into early 2022 with the provincial government lifting the workplace safety order on April 8, 2022, enabling businesses to transition back to communicable disease plans to reduce risk of all communicable disease, instead of maintaining a COVID-19 safety plan. At the same time, the provincial government also removed restrictions on gatherings and events, including at restaurants, bars, pubs and nightclubs. With the lifting of the workplace safety order, FBC accordingly adjusted its existing COVID-19 safety protocols at its worksites to balance safety with the return to normal operations. The adjustments included suspension of COVID-19 daily health check confirmation and the removal of mandatory mask wearing, although the practice of wearing a mask is still recommended. As of July 4, 2022, employees have returned to a primarily office-based work model. Employee-related activities and expenses for business purposes (i.e., travel, accommodation, etc.) have also returned to normal.

12.2.1.5 Mechanism to Return Cost Reductions to Customers

As part of the Annual Review for 2020 and 2021 Rates, FBC proposed (and was approved by Order G-42-21) to include the amounts related to incremental COVID-19 costs and cost reductions in the previously approved COVID-19 Customer Recovery Fund Deferral Account.

However, upon further review of FBC's original proposal, FBC has concluded that a better approach is to record these amounts in the Flow-through deferral account. This approach is preferable for three reasons:

1. It is consistent with the treatment of other exogenous items;
2. It will allow the O&M reported in the Annual Reports to be more reflective of the actual amounts incurred, as using the Flow-through deferral account does not result in direct adjustments to O&M, but rather one catch-all account for all flow-through adjustments. Alternatively, transferring the actual O&M savings directly to the COVID-19 Customer Recovery Fund Deferral Account would result in those O&M actual amounts being effectively booked back to the forecast amounts; and

3. The COVID-19 incremental savings will be returned to customers immediately in 2023, as opposed to over three years, which is the amortization period being proposed for the COVID-19 Customer Recovery Fund Deferral Account in Section 7.6.2.1.

From a customer perspective, there is no negative impact from the proposed change in treatment as customers will still have the full net savings returned to them. The benefit of the proposed treatment, as described above, is that the net savings will be returned to customers over one year as opposed to three years.

As such, FBC has included the O&M savings shown above in the 2022 Flow-through projection provided in Table 12-3 below, on Line 15, so that the net amount will be returned to customers in 2023 via the amortization of the Flow-through deferral account forecast in this Application.

Accordingly, FBC seeks a variance to Directive 6 of Order G-42-21. FBC requests that Directive 6 be varied as followed: "FBC is approved to record COVID-19 incremental costs and related savings from 2020 and 2021 into the Flow-through deferral account."

12.2.1.6 Conclusion

FBC proposes to refund to customers for years 2020 and 2021, via the Flow-through deferral Account, the cumulative net variance of the net incremental O&M (costs less reductions) of $1.03 million in 2023.

12.3 *ACCOUNTING MATTERS*

In the following section, FBC provides information on emerging accounting guidance.

12.3.1 Emerging Accounting Guidance

In the PBR Plan decision, the BCUC directed FBC to "communicate any accounting policy changes and updates to the Commission and other stakeholders as part of the Annual Review process during the PBR period." While this directive was not included as part of the MRP Decision, FBC will continue to provide accounting policy changes and updates as part of the Annual Review materials.

There are no new accounting policy changes that FBC is proposing, or that are required to be implemented under US GAAP, that result in a change in accounting for 2023; however, FBC provides an update on its exemptive relief to report under US GAAP.

12.3.1.1 Ontario Securities Commission Exemption to use US GAAP

FBC follows US GAAP for both financial and regulatory accounting purposes. Since 2011, FBC has made use of an exemption from the Ontario Securities Commission (OSC) permitting FBC to prepare and file its financial statements in accordance with US GAAP. Like other reporting issuers, FBC also has the option to obtain an exemption permitting the use of US GAAP by

qualifying as a US Securities and Exchange Commission Issuer (SEC Issuer) pursuant to Canadian securities law. During 2022, FBC sought and received approval from its primary securities regulator, the BC Securities Commission (BCSC), for the same exemptive relief as the 2011 OSC exemption. FBC's original exemption from 2011 was filed jointly with FBC's parent company Fortis Inc., whose primary securities regulator is the OSC; however, Fortis Inc. is now an SEC Issuer and no longer makes use of the OSC exemption. As a result, FBC obtained an exemption on a stand-alone basis from the BCSC.

The BCUC has approved FBC's use of US GAAP for regulatory accounting purposes since 2011.[60] As part of the most recent BCUC approval to use US GAAP, the BCUC directed the following:[61]

> Approval is granted until such time as the FortisBC Utilities no longer has an Ontario Securities Commission exemption to use US GAAP or is no longer reporting under US GAAP for financial reporting purposes.

FBC considers that the intention of the above direction was to ensure that FBC has an exemption from its securities regulator to use US GAAP, and not that an exemption specifically from the OSC was required, as opposed to a different securities regulator that had jurisdiction. It was not contemplated at the time of the above direction that FBC would make use of a BCSC exemption rather than an OSC exemption.

To ensure that FBC has approval from the BCUC to use US GAAP for regulatory accounting purposes, FBC is seeking a variance of Directive 2 to Order G-83-14 to remove the reference to the OSC, so that it removes the reference to the Ontario Securities Commission, and states:

> Approval is granted until such time as FBC no longer has an exemption to prepare and file its financial statements in accordance with US GAAP or is no longer reporting under US GAAP for financial reporting purposes.

FBC notes that there have been no other changes in circumstances beyond the change in the regulatory body granting exemptive relief. However, similar to the original 2011 OSC exemptive relief, the 2022 BCSC exemptive relief is not permanent and would expire January 1, 2027 unless extended further. Should FBC plan to no longer report under US GAAP (e.g., convert from US GAAP to IFRS), it would file an application for approval from the BCUC at that time

12.4 *NON-RATE BASE DEFERRAL ACCOUNTS*

FBC maintains both rate base and non-rate base deferral accounts. Rate base deferral accounts are included in rate base and earn a rate base return. In contrast, non-rate base deferral accounts are outside of rate base and may have varying rates of return, depending on the nature of the account and the return approved by the BCUC.

[60] Order G-117-11 dated July 7, 2011 and Order G-83-14 dated July 3, 2014.
[61] Order G-83-14, Directive 2.

In the following section, FBC provides information on its Flow-through deferral account. Information on FBC's non-rate base earnings sharing deferral account is included in Section 10.

12.4.1 New Deferral Accounts

FBC is not seeking approval of any new non-rate base deferral accounts in this Application.

12.4.2 Existing Deferral Accounts

In the section below, FBC discusses the Flow-through deferral account.

12.4.2.1 Flow-Through Deferral Account (2020-2024)

As approved by Order G-166-20, the Flow-through deferral account is used to capture the annual variances between the approved and actual amounts for all costs and revenues which are forecast annually, are not subject to earnings sharing, and which do not have a previously approved deferral account. The specific items included in the Flow-through deferral account were set out in Table C4-1 of the MRP Application, reproduced below.

Table 12-2: Variances Captured in the Flow-through Deferral Account

	FEI	FBC
Delivery Revenues (FEI):		
Residential and commercial use rate variances	RSAM	N/A
Customer variances	Flow-through deferral	N/A
Industrial and all other revenue variances	Flow-through deferral	N/A
Revenues and Power Supply (FBC):		
Revenue variances	N/A	Flow-through deferral
Power Supply variances net of PSI	N/A	Flow-through deferral
Gross O&M:		
Index-based O&M variances	Subject to earnings sharing	Subject to earnings sharing
BCUC fees variances	BCUC variances deferral	BCUC variances deferral
Pension & OPEB variances	Pension/OPEB variances deferral	Pension/OPEB variances deferral
All other O&M variances [1,3]	Flow-through deferral	Flow-through deferral
Capitalized Overhead:		
Capitalized overhead variances	No variance	No variance
Depreciation and Amortization:		
Depreciation rate variances	No variance	No variance
Depreciation on Clean Growth Projects [2,3]	Flow-through deferral	Flow-through deferral
Other depreciation variances	Subject to earnings sharing	Subject to earnings sharing
Amortization of deferrals	No variance	No variance
Property Tax:		
Property tax variances	Flow-through deferral	Flow-through deferral
Other Revenues :		
SCP Mitigation revenues variances	SCP Revenues deferral	N/A
CNG/LNG Recoveries variances	CNG/LNG Recoveries deferral	N/A
Revenues from Clean Growth Projects [2,3]	Flow-through deferral	Flow-through deferral
All other other revenue/income variances	Subject to earnings sharing	Subject to earnings sharing
Interest Expense/Cost of Debt:		
Interest on RSAM/CCRA/MCRA/Gas storage	Interest on RSAM/CCRA/MCRA/Gas Storage	N/A
Interest rate variances	Flow-through deferral	Flow-through deferral
Interest on Clean Growth Projects [2,3]	Flow-through deferral	Flow-through deferral
Other interest variances	Subject to earnings sharing	Subject to earnings sharing
Income Tax:		
Income tax rate variances	Flow-through deferral	Flow-through deferral
Income tax on Clean Growth Projects [2,3]	Flow-through deferral	Flow-through deferral
Other income tax variances	Subject to earnings sharing	Subject to earnings sharing

1: Including items forecast outside of the formula such as insurance premiums, NGT stations, biomethane, variable LNG production, integrity digs and EV charging stations.
2: Cost of service for NGT fueling stations and tankers, variable LNG production, and EV stations will be captured in the Flow-through deferral account.
3: Biomethane other revenues will continue to capture the actual cost of service of the biomethane capital assets and transfer it to the BVA

In accordance with the method set out in the table above, the calculation of the 2022 Projected Flow-through amount of $5.007 million credit is shown in Table 12-3 below. To calculate the amount to be distributed to customers, FBC has also included the following adjustment:

- The $4.618 million credit difference between the projected ending 2021 deferral account credit balance of $3.927 million[62] embedded in 2022 rates, and the actual ending 2021 deferral credit balance of $8.545 million. A more detailed breakout of the 2021 variance is provided in Table 12-4 below. FBC notes that the financing return on this account is included in the aggregate financing of deferral accounts at Section 11, Schedule 12.2, Line 18.

Table 12-3: 2022 Projected Flow-through Deferral Account Additions ($ millions)

Line No.	Particulars	2022 Approved	2022 Projected	After-Tax Flow-Through Variance
	(1)	(2)	(3)	(4)
1	**Total Revenue**	$ (397.294)	$ (414.292)	$ (16.998)
2				
3	**Total Power Purchase Expense**	143.779	153.164	9.385
4				
5	**Total Wheeling**	6.093	6.330	0.237
6				
7	**Total Water Fees**	11.958	11.916	(0.042)
8				
9	**Net O&M Expense**			
10	Pension & OPEB	(1.716)	(1.716)	-
11	Insurance	2.223	2.291	0.068
12	BCUC Fees	0.373	0.373	-
13	MRS	0.765	0.500	(0.265)
14	EV DCFC	0.187	0.187	-
15	COVID-19 Pandemic	-	(1.030)	(1.030)
16	Capitalized Overhead	(10.177)	(10.177)	-
17				
18	**Depreciation and Amortization**			
19	Amortization of Deferrals	1.558	1.558	-
20	Depreciation variance on Clean Growth Projects/CPCNs/Exogenous Capital	-	-	-
21	CIAC Amortization variance on Clean Growth Projects/CPCNs/Exogenous Capital	-	-	-
22				
23	**Total Property Taxes**	17.889	17.621	(0.268)
24				
25	**Other Revenues**			
26	EV Carbon Credits	-	(0.625)	(0.625)
27				
28	**Interest Expense**			
29	Long-term debt interest expense variance	41.155	41.794	0.639
30	Interest variance on Clean Growth Projects/CPCNs/Exogenous Capital	-	-	-
31	Short-term debt rate variance	-	2.253	2.253
32	Short-term debt volume variance from long-term debt issue variance	-	(1.005)	(1.005)
33	Short-term debt timing variance from long-term debt issue timing	-	0.793	0.793
34				
35	**Income Tax Expense**			
36	Income tax variance on Clean Growth Projects/CPCNs/Exogenous Capital	-	-	-
37	Income tax/CCA rate changes	-	-	-
38	Income tax on taxable flowthrough variances above (excl. Clean Growth Projects/CPCNs/Exogenous Capital)	-	1.852	1.852
39				
40	**2022 After-Tax Flow-Through Addition to Deferral Account (excluding Financing)**			**(5.007)**
41				
42	2021 Ending Deferral Account Balance True-up			(4.618)
43				
44	**2023 After-Tax Amortization**			**(9.625)**

[62] FBC Annual Review for 2022 Rates, Compliance Filing financial schedules, Schedule 12.2, Line 4, Column 2.

12.4.2.1.1 2022 PROJECTED FLOW-THROUGH VARIANCES

FBC provides the following explanations for the 2022 Projected flow-through variances shown in Table 12-3 above:

- The variance in revenue is due to increased industrial, commercial, wholesale and residential loads;
- The variance in power purchase expense is primarily due to an increase in gross load. Increasing gross load drove additional market purchases as well as BC Hydro PPA energy and capacity purchases at a higher than anticipated total cost. Rising rates further contributed to the increase in power purchase expense;
- Variances in wheeling and water fees are discussed in Section 4;
- Flow-through O&M amounts are discussed in Section 6;
- Amortization expense is equal to the approved value;
- Variances in property taxes are described in Section 9;
- Variances in other revenues are described in Section 5;
- The projected interest expense variances are derived from FBC issuing long-term debt later in 2022 than forecast, but at a higher amount and higher rate than forecast, and FBC projecting a higher short-term interest rate than the approved short-term interest rate, both as described in Section 8; and
- The income tax variance is derived as 27 percent of the aforementioned variances.

An adjustment to include the difference between the projected and final actual amounts for 2022 subject to flow-through will be recorded in the deferral account in 2022 and amortized in 2024 rates.

12.4.2.1.2 2021 FLOW-THROUGH DEFERRAL ACCOUNT TRUE-UP

As mentioned above, FBC is also providing a breakdown of the 2021 true-up amount of $4.618 million credit in Table 12-4 below, along with an explanation of the variances.

Table 12-4: 2021 Actual vs. Projected Flow-through Deferral Account Additions ($ millions)

Line No.	Particulars	2021 Projected	2021 Actual	After-Tax Flow-Through Variance
	(1)	(2)	(3)	(4)
1	**Total Revenue**	$ (389.100)	$ (404.247)	$ (15.147)
2				
3	**Total Power Purchase Expense**	141.747	152.473	10.726
4				
5	**Total Wheeling**	5.836	6.000	0.164
6				
7	**Total Water Fees**	10.878	10.741	(0.137)
8				
9	**Net O&M Expense**			
10	Pension & OPEB	0.775	0.775	-
11	Insurance	2.022	1.924	(0.098)
12	BCUC Fees	0.350	0.350	-
13	MRS	0.100	0.052	(0.048)
14	2021 Wildfires	0.155	0.155	-
15	Capitalized Overhead	(9.795)	(9.795)	-
16				
17	**Depreciation and Amortization**			
18	Amortization of Deferrals	5.110	5.110	-
19	Depreciation variance on Clean Growth Projects/CPCNs/Exogenous Capital	-	(0.301)	(0.301)
20	CIAC Amortization variance on Clean Growth Projects/CPCNs/Exogenous Capital	-	-	-
21				
22	**Total Property Taxes**	17.225	17.262	0.037
23				
24	**Interest Expense**			
25	Long-term debt interest expense variance	40.698	40.251	(0.447)
26	Interest variance on Clean Growth Projects/CPCNs/Exogenous Capital	-	(0.059)	(0.059)
27	Short-term debt rate variance	(0.500)	(0.593)	(0.092)
28	Short-term debt volume variance from long-term debt issue variance	-	0.303	0.303
29	Short-term debt timing variance from long-term debt issue timing	0.910	-	(0.910)
30				
31	**Income Tax Expense**			
32	Income tax variance on Clean Growth Projects/CPCNs/Exogenous Capital	-	0.048	0.048
33	Income tax/CCA rate changes	-	-	-
34	Income tax on taxable flowthrough variances above (excl. Clean Growth Projects/CPCNs/Exogenous Capital)	1.571	3.097	1.526
35				
36	EV DCFC Service Application 2018-2021 adjustment	0.107	(0.074)	(0.181)
37				
38	**2021 Ending Deferral Account Balance True-up**			**(4.618)**

The 2021 Actual variances shown in Table 12-4 above are described as follows:

- The favourable variance in revenue of $15.147 million was due to higher than projected residential, commercial, wholesale and irrigation loads, mainly due to weather variations. Favourable variances in residential ($12.209 million), commercial ($2.614 million), wholesale ($1.552 million), and irrigation ($0.815 million) revenue were partially offset by unfavourable variances in industrial ($1.939 million) and lighting ($0.104 million) revenue;
- The increase in power purchase expense of $10.726 million was due several factors including increased market expenses, increased load, and reduced generation availability. Increased load and market expenses were primarily due to several extreme weather events, such as the June 2021 heat dome event. This increase was partially offset by increased surplus capacity sales under the CEPSA Agreement;
- The increase in wheeling costs of $0.164 million was primarily due to increased use of wheeling under BC Hydro's Open Access Transmission Tariff;
- The decrease in water fees of $0.137 million was primarily due to reduced water rental rates compared to forecast;

- The flow-through components of O&M expense were $0.146 million lower than projected, with all items comparable to the projected amounts;
- Actual property tax expense was relatively consistent with the projected amount;
- The variance between the actual (0.81 percent) and projected (1.03 percent) short-term debt interest rates results in an amount to be returned to customers of $0.092 million,[63] shown on Line 27 of the table above. The long-term debt interest expense variance of $0.447 million to be returned to customers is due to the projected 2021 long-term debt issuance not actually occurring. The net variance of $0.607 million to be returned to customers on Lines 28 and 29 of Table 12-4 above is due to the impact of a lower actual short-term interest rate than projected, partially offset by the delay in the 2021 long-term debt issuance;
- The unfavourable income tax variance of $1.526 million is calculated as 27 percent of the aforementioned variances;
- The favourable variance of $0.181 million for the EV DCFC Service Application 2018-2021 adjustment relates to the true-up of the 2021 cost of service amounts. As discussed in the Compliance Filing to the 2022 Annual Review Decision, FBC estimated the 2018-2021 EV cost of service amounts to be a $0.107 million debit recoverable from customers, using the 2018-2020 actual cost of service amounts and a 2021 projected amount. The actual 2021 EV cost of service was lower than projected, mainly related to favourable taxes, resulting in the $0.181 million overall credit true-up amount to be returned to customers; and
- The combined favourable variance of $0.312 million related to depreciation, CIAC amortization, interest and tax variances on Clean Growth/CPCN/exogenous capital amounts, shown on Lines 19, 20, 26 and 32, respectively, were derived for 2021 by comparing the actual 2021 cost of service impacts of the UBO, Grand Forks Terminal Station and Corra Linn projects to the amounts forecast for those same projects.

12.5 *SUMMARY*

FBC has requested approval to return the incremental net cost reductions related to the COVID-19 pandemic exogenous factor to customers in 2023 through inclusion in the Flow-through deferral account. FBC has also provided an update on certain accounting related matters, and included information on the Flow-through deferral account.

[63] (0.81% - 1.03%) x $42.042 million forecast 2021 short-term debt in Schedule 26 of October 28, 2020 Evidentiary Update financial schedules.

13. SERVICE QUALITY INDICATORS

13.1 INTRODUCTION AND OVERVIEW

Under the MRP, SQIs are used to monitor the Utility's performance to ensure that any efficiencies and cost reductions do not result in a degradation of the quality of service to customers.

In the MRP Decision and Order G-166-20, the BCUC approved a balanced set of SQIs for FBC, covering safety, responsiveness to customer needs, and reliability. Eight of the SQIs have benchmarks and performance ranges set by a threshold level. Four of the SQIs are for information only and as such do not have benchmarks or performance ranges.

In the subsections below, FBC reports on its 2021 and June 2022 year-to-date performance as measured against the SQI benchmarks and thresholds. In 2021, for the eight SQIs with benchmarks, six met or were better than the benchmark, with two better than the threshold. For the four SQIs that are informational only, performance in 2021 generally remains at a level consistent with prior years. In 2022 to date, performance for the metrics with benchmarks are trending towards meeting the benchmark or the threshold.

Consistent with how SQIs were reviewed during the 2014-2019 PBR Plan term,[64] FBC has provided 2021 and year-to-date 2022 SQI results in this annual review. In accordance with Order G-44-16, the BCUC will evaluate FBC's actual 2022 SQI performance in the Annual Review for 2024 Rates when actual SQI results are known. FBC also notes that it will provide information on the 2023 year-to-date SQI results in the Annual Review for 2024 Rates.

13.2 REVIEW OF THE PERFORMANCE OF SERVICE QUALITY INDICATORS

For each SQI, Table 13-1 provides a comparison of FBC's 2021 and June year-to-date performance for 2022 to the proposed benchmarks and thresholds approved as part of the MRP. Actual 2021 and June year-to-date results for 2022 are also provided for the four informational SQIs.

[64] MRP Decision page 99: "the Panel determines that the existing approved process for interpreting metric performance is to remain in effect over the term of the MRPs."

Table 13-1: Approved SQIs, Benchmarks and Actual Performance

Performance Measure	Description	Benchmark	Threshold	2021 Results	June 2022 YTD Results
Safety SQIs					
Emergency Response Time	Percent of calls responded to within two hours	>=93%	90.6%	93%	95%
All Injury Frequency Rate (AIFR)	3 year average of lost time injuries plus medical treatment injuries per 200,000 hours worked	<=1.64	2.39	0.67	0.80
Responsiveness to Customer Needs SQIs					
First Contact Resolution	Percent of customers who achieved call resolution in one call	>=78%	74%	82%	78%
Billing Index	Measure of customer bills produced meeting performance criteria	<=3.0	5.0	0.12	0.14
Meter Reading Accuracy	Number of scheduled meters that were read	>=98%	96%	99%	99%
Telephone Service Factor (Non-Emergency)	Percent of non-emergency calls answered within 30 seconds or less	>=70%	68%	70%	63%
Customer Satisfaction Index	Informational indicator - measures overall customer satisfaction	-	-	8.4	8.4
Average Speed of Answer	Informational indicator – the amount of time it takes to answer a call (seconds)	-	-	65	98
Reliability SQIs					
System Average Interruption Duration Index (SAIDI) – Normalized	Annual SAIDI (average of cumulative customer outage time)	3.22[65]	4.52	4.27	2.94
System Average Interruption Frequency Index (SAIFI) - Normalized	Annual SAIFI (average customer outage)	1.57	2.19	2.08	1.58
Generator Forced Outage Rate	Informational indicator – Percent of time a generating unit is removed from service due to component failure or other events.	-	-	0.23%	0.85%
Interconnection Utilization	Informational indicator – percent of time that an interconnection point was available and providing electrical service to wholesale customers.	-	-	99.90%	99.91%

[65] Benchmarks and thresholds for SAIDI and SAIFI were approved in the FBC Annual Review for 2020 and 2021 Rates Decision and Order G-42-21.

In the following sections, FBC reviews each SQI's year-to-date individual performance in 2021 and 2022. Discussion is also provided for the informational SQIs.

13.2.1 Safety Service Quality Indicators

13.2.1.1 Emergency Response Time

Emergency Response Time is the time elapsed from the initial identification of a loss of electrical power (via a customer call or internal notification) to the arrival of FBC personnel on site at the trouble location. This metric provides ongoing information to assess FBC crew sizes and crew locations in response to system trouble. The target measures the percentage of emergency calls responded to within two hours. The measure is calculated as follows:

$$\frac{\text{Number of emergency calls responded to within two hours}}{\text{Total number of emergency calls in the year}}$$

There are many variables affecting the response time, including time of day (i.e., during business hours or after business hours), number and type of events (i.e., widespread outages), available resources, location (i.e., travel times and traffic congestion) and weather conditions.

The 2021 result was 93 percent which met the benchmark. The June 2022 year-to-date performance is 95 percent, which is better than the benchmark.

For comparison, the Company's annual results under the 2014-2019 PBR Plan, the 2020 and 2021 results and the June 2022 year-to-date emergency response time results are provided below. While the results have been relatively consistent, variables such as the location and severity of outage and the number of trouble calls contribute to the observed volatility in the annual performance for this metric.

Table 13-2: Historical Emergency Response Time

Description	2014	2015	2016	2017	2018	2019	2020	2021	June 2022 YTD
Results	91%	92%	97%	93%	94%	92%	92%	93%	95%
Benchmark	93%								
Threshold	90.6%								

13.2.1.2 All Injury Frequency Rate

The All Injury Frequency Rate (AIFR) is an employee safety performance indicator based on injuries per 200,000 hours worked, with injuries defined as lost time injuries (i.e., one or more days missed from work) and medical treatments (i.e., medical treatment was given or prescribed). The annual performance for this metric is calculated as:

$$\frac{\text{Number of Employee Injuries x 200,000 hours}}{\text{Total Exposure Hours Worked}}$$

For the purpose of this SQI, the measurement of performance is based on the three-year rolling average of the annual results.

The 2021 (three-year rolling average) result was 0.67 which was better than the benchmark of 1.64. The 2021 annual AIFR was 0.89 which reflected 3 Medical Treatments and 1 Lost Time Injury.

The June 2022 year-to-date performance (three-year rolling average) result is 0.80 which is better than the benchmark. The June 2022 year-to-date performance (annual) is 1.25 and reflects 2 Medical Treatments and 1 Lost Time Injury.

Strengthening the safety culture continues to be a key driver for FBC, building on the commitment to learn from safety events, identify safety hazards, assess risk and continually improve through the implementation and sustainment of robust safety barriers and controls.

For comparison, the Company's results under the 2014 to 2019 PBR Plan, the 2020 and 2021 results and the June 2022 year-to-date AIFR results are provided below.

Table 13-3: Historical All Injury Frequency Rate Results

Description	2014	2015	2016	2017	2018	2019	2020	2021	June 2022 YTD
Annual Results	3.21	1.54	1.15	1.13	1.56	0.46	0.66	0.89	1.25
Three year rolling average	2.58	2.52	1.97	1.27	1.28	1.06	0.87	0.67	0.80
Benchmark	1.64								
Threshold	2.39								

13.2.2 Responsiveness to Customer Needs Service Quality Indicators

13.2.2.1 First Contact Resolution

First Contact Resolution (FCR) measures the percentage of customers who receive resolution to their issue in one contact with FBC. The Company determines the FCR results using a customer survey, tracking the number of customers who responded that their issue was resolved in the first contact with the Company. The FCR rate is impacted by factors such as the quality and effectiveness of the Company's coaching and training programs and the composition of the different call drivers.

The 2021 result was 82 percent which was better than the benchmark of 78 percent. The June 2022 year-to-date performance is 78 percent which meets the benchmark.

For comparison, the Company's results under the 2014 to 2019 PBR Plan, the 2020 and 2021 results and the June 2022 year-to-date results are provided below.

Table 13-4: Historical First Contact Resolution Levels

Description	2014	2015	2016	2017	2018	2019	2020	2021	June 2022 YTD
Annual Results	73%	76%	79%	80%	82%	82%	82%	82%	78%
Benchmark	78%								
Threshold	72%						74%		

13.2.2.2 Billing Index

The Billing Index indicator tracks the effectiveness of the Company's billing system by measuring the percentage of customer bills produced meeting performance criteria. The Billing Index is a composite index with three components:

- Billing completion (percent of accounts billed within two days of the billing due date);
- Billing timeliness (percent of invoices delivered to Canada Post within two days of file creation); and
- Billing accuracy (percent of bills without a production issue based on input data).

The objective is to achieve a score of five or less.

The Billing Index is impacted by factors such as the performance of the Company's billing system, weather variability, which can cause a high volume of billing checks and estimation issues, and mail delivery by Canada Post.

The 2021 result was 0.12 which was better than the benchmark of 3.0. No significant billing issues occurred in 2021. The June 2022 year-to-date result is 0.14, which is also better than the benchmark.

The 2021 Billing Index sub-measures calculation is as follows.

Table 13-5: Calculation of 2021 Billing Index

Billing sub-measure	Percent Achieved (PA)	Formula		Result
Billing Accuracy (Percent of bills without a Production Issue, based on input data); Target: 99.9%	100.00%	If (PA≥99.9%,5000*(1 - PA),100*(1.05-PA))	=5000*(1-99.99885%)	0.06

Billing sub-measure	Percent Achieved (PA)	Formula		Result
Billing Timeliness (Percent of invoices delivered to Canada Post within 2 days of file creation); Target: 95%	100.00%	(100%-PA)*100	=(100%-100%)*100	0.00
Billing Completion (Percent of accounts billed within 2 days of the billing due date); Target: 95%	99.60%	(100%-PA)*100	=(100%-99.69%)*100	0.31
Billing Service Quality Indicator; Target < 3.0		(Accuracy PA+Timeliness PA+Completion PA)/3	=(0.06+0+0.31) /3	0.12

For comparison, the Company's results under the 2014 to 2019 PBR Plan, the 2020 and 2021 results and the June 2022 year-to-date results are provided below.

Table 13-6: Historical Billing Index Results

Description	2014	2015	2016	2017	2018	2019	2020	2021	June 2022 YTD
Annual Results	2.34	0.39	0.57	0.15	0.29	1.96	0.13	0.12	0.14
Benchmark	5.0						3.0		
Threshold	5.0								

13.2.2.3 Meter Reading Accuracy

This SQI compares the number of meters that are read to those scheduled to be read. Providing accurate and timely meter reads for customers is a key driver for the Company and its customers. The results are calculated as:

$$\frac{\text{Number of scheduled meters read}}{\text{Number of scheduled meters for reading}}$$

The 2021 result was 99 percent, which was better than the benchmark of 98 percent. The June 2022 year-to-date result is 99 percent, which is better than the benchmark.

For comparison, the Company's results under the 2014 to 2019 PBR Plan, the 2020 and 2021 results and the June 2022 year-to-date results are provided below.

Table 13-7: Historical Meter Reading Accuracy Results

Description	2014	2015	2016	2017	2018	2019	2020	2021	June 2022 YTD
Annual Results	98%	96%	99%	99%	99%	99%	99%	99%	99%
Benchmark	97%						98%		
Threshold	94%						96%		

13.2.2.4 Telephone Service Factor (Non-Emergency)

The Telephone Service Factor (Non-Emergency) measures the percentage of non-emergency calls that are answered in 30 seconds. It is calculated as:

$$\frac{\text{Number of non-emergency calls answered within 30 seconds}}{\text{Number of non-emergency calls received}}$$

The TSF is a measure of how well the Company can balance costs and service levels with the overall objective to maintain a consistent TSF level. This ensures the Company is staying within appropriate cost levels and maintaining adequate service for its customers. The principal factors influencing the TSF results include volume and type of inbound calls received and the resources available to answer those calls. Staffing is matched to the expected call volume based on historical data in order to reach the service level benchmark desired. Other factors that can influence the TSF are billing system related issues and weather patterns that may generate high numbers of billing related queries and the complexity of the calls.

The 2021 result was 70 percent which met the benchmark. The June 2022 year-to-date performance is 63 percent, which is below the threshold.

Several challenging circumstances were faced in the first quarter of 2022 that have contributed to a year-to-date performance in the non-emergency TSF below threshold. These challenges include higher than normal attrition levels being experienced in the contact centre coupled with colder weather that resulted in approximately 27 percent more high bill inquiries in the first quarter than the average of the preceding two years[66]. Each of these is described further below.

Customer Service is experiencing higher than expected levels of attrition, having lost approximately 20 percent of its Customer Service Representatives in 2021.[67] All exits were in the last half of 2021, resulting in fewer and less experienced employees prepared to support call volumes in the first quarter of 2022. To mitigate the impact of this, FBC accelerated the timing of planned new hire classes as well as the size of new hire classes in both 2021 and 2022. While

[66] FBC experienced approximately 1,000 high bill inquiries in Q1 2022 which compares to an average of approximately 790 in the first quarter for the two-year period 2020-2021.

[67] On average, FBC has approximately 20 customer service representatives, and 4 left the organization in the latter part of 2021. This compares to typical annual attrition in the range of 1-2 customer service representatives from the organization.

some success has been achieved, FBC has continued to face challenges recruiting and retaining newly hired contact centre employees in 2022. In addition, it takes on average approximately 12 months for new employees to be proficient and fully trained in order to support all customer inquiries and calls, and as such, average call handle times remain higher than normal while a greater portion of employees gain this experience.

High bill inquiries are expected in the first quarter of the year and planned for with staffing levels and schedules adjusted, new hire classes timed accordingly, and refresher training offered to those employees who may need it. However, the colder temperatures resulted in a volume of high bill inquiries that was greater than anticipated and lasted longer than typical, carrying into April instead of early March. This particular call type is often longer in duration and may also result in follow-up work and investigation. As noted above, there were fewer and less experienced employees prepared to support these types of calls. Thus, the contact centre experienced the compounding impact of fewer employees along with a higher volume of this call type, resulting in overall longer average wait times and a lower percentage of calls answered within thirty seconds or less.

Although the start of 2022 has been challenging, strong performance in first contact resolution, in addition to the promotion of self-service and the call back feature, continues to mitigate the impacts of lower TSF on customer experience and service quality. Further, the recovery of the non-emergency TSF remains a focus, with FBC expecting to recover to threshold levels on a year-to-date basis within the fourth quarter. Finally, the customer service index has remained high throughout 2021 and 2022 to date, indicating that the mitigation measures and focus on first contact resolution continue to result in an overall high quality of service being experienced by customers.

For comparison, the Company's results under the 2014 to 2019 PBR Plan, the 2020 and 2021 results and the June 2022 year-to-date results are provided below. As discussed in the Annual Review for 2015 Rates, the 2014 result was negatively impacted by events such as the first verified meter readings occurring after the IBEW labour disruption ended in December 2013, introduction of the Residential Conservation Rate, and the integration of the City of Kelowna customers.

Table 13-8: Historical TSF Results

Description	2014	2015	2016	2017	2018	2019	2020	2021	June 2022 YTD
Annual Results	48%	71%	70%	70%	72%	70%	70%	70%	63%
Benchmark					70%				
Threshold					68%				

13.2.2.5 Customer Satisfaction Index

The Customer Satisfaction Index (CSI) is an informational indicator that measures overall customer satisfaction with the Company. The index reflects customer feedback about important service touch points including the contact centre, perceived accuracy of meter reading, energy conservation information and field services. The index includes feedback from both residential and commercial customers. The survey is conducted quarterly, and results are presented as a score out of ten.

The CSI survey investigates service quality as well as customer attitudes that are often influenced by factors outside the Company's control. Important examples include storm-related unplanned outages and media coverage.

The annual CSI score for 2021 was 8.4, slightly lower than that obtained in 2020. There were no statistically significant shifts from 2020 to 2021 in the five measures that make up the overall customer satisfaction score. The score for overall satisfaction, which has the highest weighting, decreased from 8.5 in 2020 to 8.4 in 2021. The scores for satisfaction with the energy conservation information and contact centre metrics decreased from 7.6 in 2020 to 7.5 in 2021, and 8.5 in 2020 to 8.4 in 2021, respectively. In addition, the scores for the satisfaction with the accuracy of meter reading and field services metrics remained static at 8.2 and 9.0 in 2021, respectively.

The score for 2022 year-to-date is 8.4, consistent with the annual score recorded for 2021. Of the five measures that make up the overall customer satisfaction score, the results for June 2022 year-to-date were higher in one area, lower in one, and static in three when compared to the annual 2021 scores. The score for the satisfaction with the accuracy of meter reading metric increased from 8.2 to 8.3. The score for the satisfaction with field services metric decreased from 9.0 to 8.8. The scores for the overall satisfaction, energy conservation information, and contact centre metrics were static at 8.4, 7.5 and 8.4, respectively, from results achieved in 2021. None of these changes are statistically significant.

For comparison, the Company's results under the 2014 to 2019 PBR Plan, the 2020 and 2021 results and the June 2022 year-to-date results are provided below.

Table 13-9: Historical Customer Satisfaction Results

Description	2014	2015	2016	2017	2018	2019	2020	2021	June 2022 YTD
Annual Results	8.1	8.1	8.2	8.2	8.3	8.5	8.5	8.4	8.4
Benchmark	n/a								
Threshold	n/a								

13.2.2.6 Average Speed of Answer

The Average Speed of Answer (ASA) is an informational indicator that measures the amount of time it takes for a customer service representative to answer a customer's call (seconds).

The 2021 result was 65 seconds, and the June 2022 year-to-date performance is 98 seconds.

As with previous years, 2021 remained within a reasonable range from a customer experience perspective in that, on average, calls to the contact centre were answered in and around the one-minute mark. With respect to 2022, the year-to-date performance reflects the challenging circumstances in the first quarter of the year described above for the Telephone Service Factor (Non-Emergency). Recovery of the ASA back towards normal performance is expected to continue through the remainder of the year.

For comparison, the Company's results under the 2014 to 2019 PBR Plan, the 2020 and 2021 results and the June 2022 year-to-date results are provided below.[68]

Table 13-10: Average Speed of Answer

Description	2014	2015	2016	2017	2018	2019	2020	2021	June 2022 YTD
Annual Results	226	49	48	49	49	49	71	65	98
Benchmark	n/a								
Threshold	n/a								

13.2.3 Reliability Service Quality Indicators

FBC measures transmission and distribution system reliability according to the Institute of Electrical and Electronics Engineers (IEEE) method of normalizing reliability statistics by excluding "major events". Major events are identified as those that cause outages exceeding a threshold number of customer-hours. Threshold values are calculated by applying a statistical method called the "2.5 Beta" adjustment to historical reliability data. Any single outage event that exceeds the threshold value is excluded from the reliability data. Excluding major events allows them to be studied separately and reveals trends in daily operations that would be hidden or skewed if they were included in the data set. Major event days in the FBC service territory have been caused by mudslides, wind or snow storms, and wildfires.

Reported outages included in these measures are of one minute or longer in duration, which is consistent with the Canadian Electricity Association (CEA) standard for reporting.

[68] ASA in 2014 is higher than other years due to the impact of the six months of job action that took place in Q3 and Q4 of 2013. This job action resulted in a higher number of bill estimates, which led to a higher volume of customer inquiries in 2014 as bill adjustments were made reflecting actual meter reads.

13.2.3.1 System Average Interruption Duration Index (SAIDI) – Normalized

SAIDI is the amount of time the average customer's power is off during the year (i.e., the total amount of time the average customer's clock would lose during a year), after adjusting for the impact of major events as described above, and is calculated as follows:

$$\frac{\text{Total Customer Hours of Interruption}}{\text{Total Number of Customers Served}}$$

Customer Hours of Interruption related to a power outage are calculated by multiplying the number of customers affected by the outage by the duration of the outage.

For the purpose of this SQI, the measurement of performance is based on the annual results.

The 2021 result was 4.27 which was better than the threshold of 4.52 but below the benchmark of 3.22. The June 2022 year-to-date performance is 2.94 which is better than the benchmark. The 2021 results were negatively impacted by multiple external factors which did not meet the threshold for normalization.

The July 2021 results were nearly five times the three-year average and were heavily influenced by several factors that did not meet the threshold for normalization. The largest single event that influenced the July results was the collapse of a construction crane on July 12 in downtown Kelowna. The immediate response to this event was to de-energize a large portion of the surrounding area so that first responders could safely attend to the scene. This incident interrupted power to over 2,600 customers and accounted for over 36,000 customer hours interrupted.

British Columbia also experienced an unprecedented run of extreme heat at the end of June and early July which dried forest fuels earlier than usual and led to one of the worst fire seasons on record. FBC transmission and distribution infrastructure were both impacted by the wildfires with dozens of structures burned to the ground. The largest single outage due to these fires was in the Oliver area and contributed over 21,000 customer hours to July.

In addition to the damaged infrastructure, FBC Operations proactively de-energized portions of the system at the request of BC Wildfire Services to assist in fire suppression efforts. System operations were also impacted by proactively disabling automatic line reclosing in parts of the system to reduce the risk of igniting a fire from trees contacting FBC lines. This led to larger and longer outages in areas of the system where automatic line reclosing was disabled to allow field crews time to assess the cause and confirm that it was safe to re-energize the system. FBC estimates that the combination of fire damage, proactive de-energization, and disabling of automatic line reclosing contributed to over 52,000 customer hours of interruption in July.

There were three Major Event Days that met the threshold for normalization in 2021:

- On January 13, a major windstorm across the Okanagan and Kootenays caused approximately 11,000 customer-interruptions and totalled over 155,000 customer-hours of interruption.
- On April 18, a major windstorm across the West Kootenays qualified for a Major Event Day causing approximately 19,800 customer-interruptions and totalled over 200,800 customer-hours of interruption.
- On November 15, a major storm affected multiple areas in the Okanagan causing approximately 27,474 customer-interruptions and totalled over 218,720 customer-hours of interruption. This event is the highest total customer-hours of interruption FBC has on record (back to 2003).

There have been no Major Event Days in 2022 to-date.

For comparison, the Company's results under the 2014 to 2019 PBR Plan, the 2020 and 2021 results and the June 2022 year-to-date results are provided below. From 2014 to 2019, the benchmark and the threshold reflect the values established under the PBR Plan using three-year rolling average results. Starting in 2020, the benchmark and threshold reflect the values approved by the BCUC for the MRP term.[69]

Table 13-11: Historical SAIDI Results

Description	2014	2015	2016	2017	2018	2019	2020	2021	June 2022 YTD
Annual normalized results	2.32	2.13	2.10	4.05	3.15	2.45	3.17	4.27	2.94
Benchmark	2.22						3.22		
Threshold	2.62						4.52		

13.2.3.2 System Average Interruption Frequency Index (SAIFI) – Normalized

SAIFI is the average number of interruptions per customer served per year (i.e., the number of times the average customer would have to reset their clock during the year), after adjusting for the impact of major events as described above, and is calculated as follows:

$$\frac{\text{Total Number of Customer Interruptions}}{\text{Total Number of Customers Served}}$$

The Number of Customer Interruptions related to a power outage is the number of customers affected by the outage.

[69] The benchmark and threshold for SAIDI were approved in the FBC Annual Review for 2020 and 2021 Rates Decision and Order G-42-21.

For the purpose of this SQI, the measurement of performance is based on the annual results.

The 2021 result was 2.08 and the June 2022 year-to-date performance is 1.58, with both better than the threshold of 2.19. The 2021 results for SAIFI were similarly impacted by the crane collapse, wildfires and storms that were discussed in the SAIDI section. FBC also completed system upgrades on several radial transmission lines where no alternate supply was available which impacted a large number of customers. These outages were scheduled in advance during "off peak" hours to minimize the impact to homes and businesses.

For comparison, the Company's results under the 2014 to 2019 PBR Plan, the 2020 and 2021 results and the June 2022 year-to-date results are provided below. From 2014 to 2019, the benchmark and the threshold reflect the values established under the PBR Plan using three-year rolling average results. Starting in 2020, the benchmark and threshold reflect the values approved by the BCUC for the MRP term.[70]

Table 13-12: Historical SAIFI Results

Description	2014	2015	2016	2017	2018	2019	2020	2021	June 2022 YTD
Annual normalized results	1.64	1.56	1.34	1.78	1.73	1.21	1.64	2.08	1.58
Benchmark	1.64						1.57		
Threshold	2.50						2.19		

13.2.3.3 Generator Forced Outage Rate

Generator Forced Outage Rate (GFOR), an informational indicator, is a measure of the percentage of time in one year that the generating units experienced forced outages compared to the amount of time they could have operated without a forced outage. A forced outage means the removal of a generating unit from service due to the occurrence of a component failure or other event, making it unavailable to produce power due to the unexpected breakdown. The GFOR is defined by the CEA as follows:

$$\frac{\text{Total Forced Outage Time}}{\text{Total Forced Outage Time + Total Operating Time}} \text{ X } 100$$

The 2021 result for GFOR was 0.23 percent. The June 2022 year-to-date performance is 0.85 percent.

For comparison, the Company's results under the 2014 to 2019 PBR Plan, the 2020 and 2021 results and the June 2022 year-to-date results are provided below.

[70] The benchmark and threshold for SAIFI were approved in the FBC Annual Review for 2020 and 2021 Rates Decision and Order G-42-21.

Table 13-13: Historical Generator Forced Outages

	2014	2015	2016	2017	2018	2019	2020	2021	June 2022 YTD
FBC	1.7%	0.1%	0.8%	0.6%	0.4%	0.1%	1.3%	0.23%	0.85%
CEA	6.3%	6.2%	6.2%	6.2%	6.7%	4.9%	4.60	TBD	

13.2.3.4 Interconnection Utilization

Interconnection Utilization, an informational indicator, is a measurement of the time that an interconnection point was available and providing electrical service to the municipal wholesale customers (City of Penticton, City of Summerland, City of Grand Forks and City of Nelson). There are twelve points of interconnection combined between the four customers.

The Interconnection Utilization metric for the interconnection points listed is calculated as follows:

$$\frac{\text{Total Operating Hours}}{\text{Total Operating Hours + Total Outage Time}}$$

The 2021 result of 99.90 percent and June 2022 year-to-date result of 99.91 percent are generally consistent with prior years' results. The City of Nelson interconnection at Coffee Creek was negatively impacted by two of the three Major Events on the FBC system described previously in the SAIDI section. For comparison, the Company's results under the 2014 to 2019 PBR Plan, the 2020 and 2021 results and the June 2022 year-to-date results are provided below.

Table 13-14: Interconnection Utilization

Description	2014	2015	2016	2017	2018	2019	2020	2021	June 2022 YTD
Interconnection Utilization	99.99%	99.94%	99.99%	99.95%	99.96%	99.98%	99.89%	99.90%	99.91%
Benchmark	n/a								
Threshold	n/a								

13.3 *SUMMARY*

In summary, FBC's 2021 and June 2022 year-to-date SQI results indicate that the Company's overall performance meets service quality requirements. In 2021, for the eight SQIs with benchmarks, six met or were better than the benchmark with two better than the threshold. For the four SQIs that are informational only, performance in 2021 generally remains at a level consistent with prior years.

Appendix A

LOAD FORECAST SUPPLEMENTARY INFORMATION

Table A1-1: Consumer Price Index (CPI)

Products and product groups[3, 4]	All-items
Reference period	
	2002=100
July 2020	132.6
August 2020	132.4
September 2020	132.5
October 2020	132.9
November 2020	133.3
December 2020	132.8
January 2021	133.6
February 2021	134.1
March 2021	134.9
April 2021	135.2
May 2021	135.1
June 2021	135.8
July 2021	136.7
August 2021	137.0
September 2021	137.2
October 2021	137.9
November 2021	138.1
December 2021	138.0
January 2022	139.4
February 2022	140.4
March 2022	143.0
April 2022	144.2
May 2022	146.1
June 2022	146.5

Table A1-2: Average Weekly Earnings (AWE)

North American Industry Classification System (NAICS)[5]		Industrial aggregate excluding unclassified businesses[6, 7]
Geography	Reference period	
		Dollars
British Columbia (map)	July 2020	1,093.72[B]
	August 2020	1,089.35[B]
	September 2020	1,093.75[B]
	October 2020	1,095.32[B]
	November 2020	1,102.95[B]
	December 2020	1,110.36[B]
	January 2021	1,113.22[B]
	February 2021	1,114.21[B]
	March 2021	1,107.66[B]
	April 2021	1,112.04[B]
	May 2021	1,118.59[B]
	June 2021	1,115.40[B]
	July 2021	1,140.52[B]
	August 2021	1,142.40[B]
	September 2021	1,139.64[B]
	October 2021	1,136.85[B]
	November 2021	1,132.25[B]
	December 2021	1,134.84[B]
	January 2022	1,157.19[B]
	February 2022	1,153.88[B]
	March 2022	1,161.22[B]
	April 2022	1,176.54[B]

Table A1-3: British Columbia Two-Year Outlook 2022

Key Economic Indicators: British Columbia, 2021-23
(forecast completed February 18, 2022)

	2021Q1	2021Q2	2021Q3	2021Q4	2022Q1	2022Q2	2022Q3	2022Q4	2023Q1	2023Q2	2023Q3	2023Q4	2021	2022	2023
GDP at market prices ($ millions)	328,577	329,385	334,551	339,673	343,417	348,045	350,673	353,935	356,447	359,588	361,919	364,178	333,047	349,017	360,533
	1.5	*0.2*	*1.6*	*1.5*	*1.1*	*1.3*	*0.8*	*0.9*	*0.7*	*0.9*	*0.6*	*0.6*	*7.7*	*4.8*	*3.3*
GDP at market prices (2012 $ millions)	278,978	277,225	279,564	281,275	283,897	288,030	290,551	293,351	295,260	297,122	298,139	299,057	279,261	288,957	297,395
	0.7	*-0.6*	*0.8*	*0.6*	*0.9*	*1.5*	*0.9*	*1.0*	*0.7*	*0.6*	*0.3*	*0.3*	*4.7*	*3.5*	*2.9*
GDP at basic prices (2012 $ millions)	258,225	257,607	258,824	259,977	262,651	266,678	269,275	272,107	273,828	275,566	276,523	277,352	258,659	267,678	275,817
	0.5	*-0.2*	*0.5*	*0.4*	*1.0*	*1.5*	*1.0*	*1.1*	*0.6*	*0.6*	*0.3*	*0.3*	*4.8*	*3.5*	*3.0*
Consumer price index (2002 = 1.000)	1.342	1.354	1.370	1.380	1.401	1.412	1.424	1.433	1.441	1.449	1.456	1.463	1.361	1.418	1.452
	0.9	*0.9*	*1.2*	*0.7*	*1.6*	*0.7*	*0.9*	*0.6*	*0.6*	*0.6*	*0.5*	*0.5*	*2.8*	*4.1*	*2.5*
Implicit price deflator—GDP at market prices	1.178	1.188	1.197	1.208	1.210	1.208	1.207	1.207	1.207	1.210	1.214	1.218	1.193	1.208	1.212
(2012 = 1.000)	*0.8*	*0.9*	*0.7*	*0.9*	*0.2*	*-0.1*	*-0.1*	*0.0*	*0.1*	*0.2*	*0.3*	*0.3*	*2.9*	*1.3*	*0.4*
Wages and salary per employee ($ 000s)	54.6	55.5	56.8	57.2	57.3	57.2	57.3	57.6	57.9	58.1	58.5	58.8	56.0	57.3	58.3
	1.2	*1.7*	*2.2*	*0.8*	*0.1*	*-0.1*	*0.2*	*0.5*	*0.5*	*0.5*	*0.5*	*0.6*	*4.1*	*2.3*	*1.7*
Primary household income ($ millions)	232,341	235,256	242,425	248,720	249,890	251,061	252,734	254,925	256,921	259,217	261,239	263,382	239,685	252,153	260,190
	1.9	*1.3*	*3.0*	*2.6*	*0.5*	*0.5*	*0.7*	*0.9*	*0.8*	*0.9*	*0.8*	*0.8*	*9.1*	*5.2*	*3.2*
Household disposable income ($ millions)	210,080	211,206	215,909	216,925	215,827	216,553	218,063	219,981	220,758	222,983	224,889	226,886	213,530	217,606	223,879
	1.2	*0.5*	*2.2*	*0.5*	*-0.5*	*0.3*	*0.7*	*0.9*	*0.4*	*1.0*	*0.9*	*0.9*	*2.4*	*1.9*	*2.9*
Household net savings rate (per cent)	7.3	7.8	4.5	4.2	3.3	2.9	3.1	3.3	2.8	2.8	2.6	2.5	6.0	3.1	2.7
Population (000s)	5,164	5,186	5,215	5,250	5,259	5,268	5,276	5,284	5,296	5,307	5,320	5,332	5,204	5,272	5,314
	0.1	*0.4*	*0.6*	*0.7*	*0.2*	*0.2*	*0.2*	*0.2*	*0.2*	*0.2*	*0.2*	*0.2*	*1.0*	*1.3*	*0.8*
Employment (000s)	2,629	2,631	2,669	2,696	2,694	2,685	2,690	2,698	2,704	2,714	2,718	2,723	2,656	2,692	2,715
	1.6	*0.1*	*1.4*	*1.0*	*-0.1*	*-0.3*	*0.2*	*0.3*	*0.2*	*0.4*	*0.2*	*0.2*	*6.6*	*1.3*	*0.9*
Labour force (000s)	2,836	2,825	2,846	2,852	2,850	2,858	2,866	2,872	2,877	2,882	2,887	2,892	2,840	2,862	2,884
	1.4	*-0.4*	*0.8*	*0.2*	*-0.1*	*0.3*	*0.3*	*0.2*	*0.2*	*0.2*	*0.2*	*0.2*	*3.7*	*0.8*	*0.8*
Labour force participation rate (per cent)	65.6	65.2	65.3	65.0	64.8	64.8	64.9	64.8	64.8	64.7	64.7	64.7	65.3	64.8	64.7
Unemployment rate (per cent)	7.3	6.9	6.2	5.5	5.5	6.1	6.1	6.0	6.0	5.8	5.8	5.8	6.5	5.9	5.9
Retail sales ($ millions)	98,731	99,233	98,267	96,315	95,494	95,987	96,084	97,049	97,750	98,331	99,140	99,888	98,136	96,153	98,777
	3.7	*0.5*	*-1.0*	*-2.0*	*-0.9*	*0.5*	*0.1*	*1.0*	*0.7*	*0.6*	*0.8*	*0.8*	*12.1*	*-2.0*	*2.7*
Housing starts (units, 000s)	52,902	49,795	45,224	42,507	40,000	39,536	36,171	35,850	35,530	35,209	34,889	34,568	47,607	37,889	35,049
	30.7	*-5.9*	*-9.2*	*-6.0*	*-5.9*	*-1.2*	*-8.5*	*-0.9*	*-0.9*	*-0.9*	*-0.9*	*-0.9*	*26.2*	*-20.4*	*-7.5*
Net interprovincial migration (000s)	16.7	17.4	17.7	31.4	15.2	10.4	7.1	5.2	7.9	7.5	7.1	6.8	20.8	9.5	7.3
Net international migration (000s)	52.6	52.2	19.8	18.8	20.9	22.2	24.4	27.3	35.2	38.2	40.3	41.6	35.8	23.7	38.8

Shaded area represents forecast data, *italics indicate percentage change*.
All data are in millions of dollars, seasonally adjusted at annual rates, unless otherwise specified.
For each indicator, the first line is the level and the second line is the percentage change from the previous period.
Sources: The Conference Board of Canada; Statistics Canada; CMHC Housing Time Series Database.

Note: Table above is from the Conference Board of Canada, British Columbia Two-Year Outlook, March 30, 2022.

Appendix A2

Load Forecast Tables

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1. INTRODUCTION

This appendix provides the historical and forecast load data used in Section 3 of the Application. The tables in Section 2 show 10 years of historical data and the before-savings and after-savings forecast for 2022S and 2023F. Section 3 shows the customer forecast data while Section 4 presents the residential UPC data. The tables in Section 5 show the load forecast. Table 5.3 shows the DSM that was deducted from the before-savings forecast to provide the after-savings forecast for 2023F. Tables 6.1 and 6.2 show the variance of the customer accounts and forecasts from 2016 to 2021 when compared to the actuals. Table 6.3 shows the annual growth of customer and load that FBC has experienced since 2016. Tables 6.4 and 6.5 show the Residential UPC and Winter peak variances from forecast from 2019 to 2021. Finally, Table 6.6 shows the system load factor from the years 2016 to 2021 and the forecast load factor for 2022S and 2023F.

The tables in this appendix reflect the acquisition by FBC of the assets and customers of the City of Kelowna electric utility effective March 31, 2013. The acquisition resulted in an increase in direct customers to FBC and a re-distribution of load from wholesale to other rate classes in 2013 and 2014.

2. MONTHLY LOAD FORECAST

Forecast loads are shown:

- before-savings – the load before DSM and includes Normalized loads to December 2021.
- after-savings – the load after DSM and includes Normalized loads to December 2021.

2.1 GROSS LOAD (MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Historical Normalized Actuals													
2012	354,376	315,497	304,411	253,594	237,899	233,308	272,143	275,122	236,457	262,538	313,757	362,555	3,421,657
2013	372,939	327,919	300,296	255,888	249,987	235,093	291,183	274,786	241,239	266,317	303,923	380,406	3,499,975
2014	363,947	304,540	303,886	253,159	241,999	242,933	284,643	269,971	229,496	256,060	300,844	381,603	3,433,082
2015	365,681	319,636	299,774	250,449	249,965	245,501	286,189	276,449	233,713	256,762	300,047	361,987	3,446,152
2016	363,248	311,848	292,351	268,698	248,319	242,786	289,259	280,588	234,770	266,284	332,085	350,062	3,480,297
2017	361,265	295,737	307,586	263,795	249,642	251,284	299,544	288,941	246,701	265,695	326,103	355,527	3,511,820
2018	375,664	309,496	306,028	264,140	273,621	256,591	308,227	297,251	231,377	262,531	302,555	376,342	3,563,824
2019	372,224	288,274	315,330	261,324	268,354	257,653	298,081	293,227	260,757	291,917	313,593	371,724	3,592,459
2020	382,181	332,609	303,499	246,152	239,601	248,354	309,611	303,017	260,523	282,780	333,207	374,349	3,615,884
2021	378,637	338,019	319,817	276,739	257,155	259,320	306,943	294,834	257,175	285,567	334,065	368,654	3,676,926
Before-Savings													
2022S	393,190	335,138	331,640	280,553	267,153	271,396	321,383	310,626	274,609	295,951	337,171	383,507	3,802,317
2023F	396,339	337,950	334,411	282,950	269,568	273,870	324,232	313,473	277,139	298,596	340,037	386,627	3,835,192
After-Savings													
2022S	390,444	332,413	328,981	277,979	264,668	268,968	318,980	308,194	272,123	293,371	334,512	380,802	3,771,436
2023F	390,866	332,540	329,150	277,874	264,687	269,119	319,544	308,746	272,326	293,617	334,927	381,448	3,774,844

2.2 NET LOAD (MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Historical Normalized Actuals													
2012	321,730	286,779	279,732	235,517	222,312	217,842	252,099	254,667	220,598	243,793	286,926	328,517	3,150,511
2013	337,728	297,641	276,667	237,842	233,199	219,696	268,867	254,751	225,078	247,419	279,078	343,897	3,221,865
2014	330,080	277,952	279,588	235,366	226,108	226,460	263,122	250,470	214,691	238,394	276,319	344,675	3,163,224
2015	331,359	290,442	275,968	232,925	232,996	228,619	264,346	255,968	218,317	238,919	275,526	328,297	3,173,683
2016	329,697	284,239	269,871	248,933	231,743	226,433	267,219	259,761	219,415	247,393	302,834	318,710	3,206,245
2017	327,600	270,353	282,545	244,429	232,661	233,596	275,700	266,639	229,612	246,617	297,428	322,834	3,230,015
2018	340,082	282,343	281,627	245,049	253,803	238,507	283,500	274,131	216,479	244,187	277,988	340,643	3,278,339
2019	337,457	264,607	289,706	242,736	249,368	239,550	274,993	270,833	242,244	269,708	287,514	337,042	3,305,758
2020	346,177	302,227	279,953	229,763	224,464	231,690	285,178	279,540	242,297	262,136	304,435	339,684	3,327,545
2021	345,746	308,157	294,337	255,440	238,210	239,708	282,793	272,125	237,826	263,832	306,218	337,045	3,381,436
Before-Savings													
2022S	356,872	305,644	305,096	260,549	249,414	252,595	296,341	287,118	255,390	274,469	309,030	348,812	3,501,329
2023F	359,759	308,223	307,659	262,783	251,668	254,896	298,970	289,745	257,738	276,922	311,668	351,673	3,531,705
After-Savings													
2022S	354,335	303,127	302,639	258,171	247,118	250,352	294,120	284,871	253,093	272,084	306,573	346,312	3,472,795
2023F	354,702	303,224	302,798	258,093	247,157	250,505	294,638	285,378	253,291	272,322	306,947	346,888	3,475,944

APPENDIX A2
LOAD FORECAST TABLES

2.3 RESIDENTIAL (MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Historical Normalized Actuals													
2012	134,187	105,958	112,447	88,508	81,808	82,946	97,309	91,118	73,417	89,175	117,807	154,029	1,228,709
2013	145,263	115,730	114,637	112,100	90,869	85,319	120,666	100,397	73,591	97,867	124,661	171,845	1,352,945
2014	147,191	120,724	129,852	84,813	80,792	77,673	105,443	102,753	73,260	95,314	119,531	159,107	1,296,452
2015	150,230	122,084	120,304	91,957	76,652	84,441	110,145	97,235	73,384	99,324	125,839	146,556	1,298,150
2016	147,429	121,286	113,080	99,963	91,648	85,702	101,212	96,335	77,431	96,417	129,741	135,335	1,295,580
2017	145,663	112,986	118,857	102,166	94,155	86,021	106,392	95,082	82,012	96,745	129,829	150,584	1,320,492
2018	154,740	121,081	119,975	97,261	100,276	86,146	109,349	100,153	70,342	89,942	112,695	150,638	1,312,598
2019	147,714	98,552	116,377	90,039	91,727	81,739	100,157	94,674	87,612	98,618	112,609	146,320	1,266,137
2020	150,634	126,164	117,219	93,211	89,289	91,128	111,958	103,644	86,533	100,913	126,958	149,181	1,346,832
2021	151,923	132,351	117,698	95,324	88,510	89,335	114,977	114,763	58,293	98,449	123,064	145,645	1,330,331
Before-Savings													
2022S	149,350	118,436	116,520	92,400	89,399	86,970	106,340	99,003	84,580	98,837	120,281	146,323	1,308,438
2023F	149,488	118,545	116,628	92,485	89,481	87,050	106,438	99,094	84,658	98,928	120,392	146,458	1,309,643
After-Savings													
2022S	148,891	117,988	116,106	92,031	89,075	86,679	106,062	98,712	84,257	98,468	119,867	145,876	1,304,011
2023F	148,568	117,647	115,796	91,743	88,830	86,464	105,876	98,507	84,003	98,180	119,551	145,549	1,300,714

2.4 COMMERCIAL (MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Normliazed Actuals													
2012	64,101	63,452	59,292	53,673	54,431	49,553	55,968	62,008	56,661	52,596	57,398	51,423	680,553
2013	65,750	60,623	56,214	57,036	69,494	61,665	67,834	73,941	72,704	67,185	66,229	69,533	788,208
2014	80,917	72,012	69,241	70,566	73,379	72,714	75,404	74,677	66,669	60,028	65,444	82,026	863,078
2015	81,041	74,201	68,933	64,674	71,533	72,581	71,204	71,712	68,657	62,650	66,828	79,463	853,478
2016	82,612	75,915	71,711	71,671	69,996	66,744	76,904	77,981	68,748	70,333	81,859	90,367	904,841
2017	85,017	74,211	77,360	69,012	70,513	72,529	81,817	81,344	72,335	73,835	78,070	78,916	914,960
2018	87,447	74,470	78,245	70,839	73,624	72,175	81,335	82,374	71,079	73,218	76,070	85,202	926,078
2019	86,215	75,958	80,152	69,784	72,863	72,688	80,601	81,248	73,015	75,305	77,661	86,230	931,722
2020	88,558	80,807	76,026	63,736	65,028	67,948	79,777	81,941	74,160	76,659	80,994	86,252	921,886
2021	88,860	79,418	80,125	72,153	73,680	74,618	79,949	69,139	96,038	76,264	81,554	87,844	959,641
Before-Savings													
2022S	91,281	81,781	81,825	71,225	73,270	74,552	85,487	85,537	76,428	79,040	83,178	90,148	973,752
2023F	93,329	83,616	83,662	72,825	74,916	76,228	87,409	87,461	78,147	80,815	85,045	92,172	995,624
After-Savings													
2022S	90,298	80,801	80,856	70,272	72,331	73,624	84,563	84,609	75,489	78,086	82,209	89,168	962,307
2023F	91,368	81,668	81,740	70,935	73,057	74,392	85,584	85,632	76,304	78,952	83,163	90,278	973,073

Note: The commercial class is normalized from 2014 to 2020 since weather correlation appeared in the data at that time, all numbers before 2014 are actuals.

2.5 WHOLESALE (MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Historical Normalized Actuals													
2012	96,036	85,333	81,119	66,560	58,307	59,084	69,719	70,177	60,311	72,646	82,146	97,532	898,971
2013	103,661	88,423	80,309	42,225	37,653	34,630	44,414	42,889	38,531	44,175	51,637	66,656	675,204
2014	64,115	50,647	51,900	41,917	35,985	34,959	43,081	42,482	38,972	41,116	53,678	68,270	567,123
2015	65,841	58,564	51,584	41,088	41,147	36,029	45,222	43,897	37,441	42,668	51,945	65,059	580,485
2016	64,687	55,006	49,218	43,812	36,262	35,106	48,506	43,480	37,096	43,408	59,685	58,167	574,434
2017	61,637	51,026	51,573	40,753	35,692	35,965	47,044	49,971	39,411	42,639	56,771	61,621	574,101
2018	65,721	51,837	50,293	43,769	41,467	33,766	45,024	47,275	36,478	47,576	54,103	67,407	584,715
2019	61,944	48,097	50,091	42,390	39,513	36,881	47,393	44,924	37,351	44,052	49,804	63,534	565,972
2020	64,233	56,219	48,768	39,333	33,066	35,088	44,642	44,913	39,548	45,075	55,660	62,943	569,488
2021	63,822	56,888	51,016	42,771	35,118	32,874	43,009	44,315	36,150	44,201	57,331	58,330	565,827
Before-Savings													
2022S	64,807	54,940	51,149	42,542	37,128	36,250	46,538	46,193	38,848	45,583	55,516	63,082	582,577
2023F	65,192	55,265	51,454	42,796	37,362	36,483	46,834	46,485	39,088	45,858	55,846	63,460	586,125
After-Savings													
2022S	64,456	54,593	50,813	42,220	36,821	35,954	46,246	45,897	38,540	45,261	55,180	62,735	578,717
2023F	64,492	54,573	50,785	42,156	36,752	35,895	46,253	45,897	38,481	45,223	55,184	62,779	578,470

2.6 INDUSTRIAL (MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Historical Actuals													
2012	24,973	30,356	25,036	25,285	23,707	21,432	22,094	22,115	22,666	22,863	26,328	23,917	290,771
2013	19,966	30,774	23,744	24,489	31,517	33,006	29,815	29,726	31,598	32,105	32,500	33,084	352,325
2014	35,943	32,746	26,411	34,532	30,112	32,770	29,719	22,362	30,032	38,104	35,138	33,043	380,912
2015	32,138	33,574	32,797	31,186	36,574	26,261	27,971	34,078	32,395	29,853	27,852	34,997	379,676
2016	32,901	29,835	33,180	28,953	27,588	31,785	31,632	32,805	30,120	33,350	28,559	32,687	373,396
2017	33,109	30,227	32,593	30,117	27,928	31,621	29,477	29,518	28,665	28,831	30,770	29,734	362,590
2018	30,089	33,113	31,062	30,455	32,718	39,030	38,264	35,307	33,245	30,034	33,591	35,836	402,744
2019	40,014	40,563	41,563	37,886	39,198	40,876	38,967	41,784	39,929	49,045	45,695	39,390	494,911
2020	41,115	37,485	36,324	30,596	32,632	32,899	39,933	39,350	35,590	36,265	39,250	39,794	441,233
2021	39,629	38,120	44,021	42,125	34,088	34,473	33,956	35,536	42,333	41,558	42,792	43,684	472,315
Before-Savings													
2022S	49,922	49,087	54,123	51,558	43,838	48,000	48,703	47,580	50,264	47,957	48,513	47,775	587,321
2023F	50,238	49,396	54,438	51,852	44,129	48,312	49,017	47,901	50,575	48,269	48,844	48,099	591,072
After-Savings													
2022S	49,195	48,360	53,402	50,840	43,130	47,296	48,007	46,881	49,566	47,241	47,795	47,067	578,779
2023F	48,797	47,968	53,031	50,464	42,773	46,975	47,708	46,597	49,287	46,956	47,539	46,827	574,920

2.7 LIGHTING (MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Historical Actuals													
2012	1,618	1,031	1,232	601	1,666	601	1,661	1,137	611	1,127	1,137	1,064	13,487
2013	1,532	863	1,003	1,112	1,186	1,101	1,151	1,069	1,135	1,132	1,080	1,114	13,479
2014	1,282	1,273	1,251	1,310	1,327	1,331	1,329	1,374	1,257	1,255	1,260	1,382	15,633
2015	1,319	1,339	1,261	1,321	1,372	1,382	1,299	1,347	1,248	1,349	1,295	1,359	15,891
2016	1,245	1,363	1,341	1,362	1,361	1,347	1,404	1,381	1,294	1,191	1,251	1,388	15,930
2017	1,394	1,233	1,390	1,286	1,339	1,301	1,383	1,382	1,289	1,335	1,270	1,330	15,932
2018	1,385	1,178	1,291	1,307	1,198	1,118	1,068	998	988	952	848	894	13,225
2019	907	808	873	943	965	937	917	949	955	947	909	928	11,039
2020	929	892	955	900	914	874	932	949	878	907	863	852	10,846
2021	838	774	836	795	858	787	802	805	770	851	776	791	9,682
Before-Savings													
2022S	820	759	817	809	839	797	813	829	798	830	782	789	9,682
2023F	820	759	817	809	839	797	813	829	798	830	782	789	9,682
After-Savings													
2022S	804	743	802	795	826	784	801	816	785	816	766	773	9,511
2023F	788	728	788	783	816	775	792	808	777	807	758	765	9,385

2.8 IRRIGATION (MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Historical Normalized Actuals													
2012	816	650	606	890	2,393	4,226	5,348	8,113	6,933	5,385	2,109	552	38,019
2013	1,557	1,228	759	880	2,480	3,974	4,986	6,729	7,519	4,955	2,970	1,666	39,704
2014	633	549	932	2,227	4,512	7,013	8,146	6,822	4,501	2,578	1,267	847	40,025
2015	790	680	1,089	2,698	5,718	7,925	8,506	7,700	5,192	3,074	1,768	863	46,003
2016	822	834	1,341	3,172	4,888	5,748	7,561	7,778	4,724	2,694	1,739	765	42,065
2017	780	670	772	1,096	3,035	6,160	9,587	9,343	5,898	3,231	719	649	41,939
2018	700	662	761	1,419	4,521	6,271	8,461	8,024	4,348	2,465	681	666	38,979
2019	663	630	650	1,694	5,103	6,429	6,958	7,254	3,381	1,741	835	640	35,978
2020	708	660	662	1,987	3,535	3,752	7,936	8,743	5,588	2,317	709	662	37,260
2021	674	606	641	2,272	5,957	7,621	10,099	7,568	4,242	2,508	701	751	43,640
Before-Savings													
2022S	692	642	661	2,015	4,940	6,025	8,459	7,976	4,472	2,222	760	695	39,559
2023F	692	642	661	2,015	4,940	6,025	8,459	7,976	4,472	2,222	760	695	39,559
After-Savings													
2022S	691	641	660	2,013	4,935	6,015	8,442	7,956	4,456	2,213	756	693	39,471
2023F	690	640	659	2,011	4,930	6,004	8,425	7,936	4,440	2,204	752	691	39,382

2.9 SYSTEM PEAK (MW)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Winter	Summer
Historical Normalized Actuals														
2012	702	675	560	523	493	418	589	540	453	501	624	723	723	589
2013	720	631	549	493	515	442	600	565	523	502	598	698	698	600
2014	651	580	562	469	403	482	620	605	412	467	572	645	693	620
2015	693	679	568	488	501	523	611	587	437	514	669	631	685	611
2016	685	683	569	540	490	582	587	593	443	480	613	724	755	593
2017	755	673	595	510	597	505	600	605	561	515	594	648	714	605
2018	714	648	583	516	602	533	630	631	429	459	609	659	682	631
2019	678	682	651	514	568	502	626	639	538	562	622	701	732	639
2020	732	680	609	500	482	515	666	665	551	549	631	667	731	666
2021	711	731	555	495	488	653	597	635	486	509	628	675	685	653
Before-Savings														
2022S	725	687	608	516	488	588	658	661	502	537	645	722	783	679
2023F	732	693	614	521	493	593	664	667	506	542	650	728	788	685
After-Savings														
2022S	725	686	608	515	488	587	657	660	501	536	644	721	782	678
2023F	730	692	612	519	491	592	662	665	505	540	649	727	786	684

Note: The peaks shown in the table above are seasonal peaks. The seasonal winter peak is based on November and December of the current year and January and February of the following year. The seasonal summer peak is based on June, July and August of the current year and includes the June 2021 Heat Dome.

3. CUSTOMER FORECAST

3.1 CUSTOMERS

Customer Count	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022S	2023F
Residential	99,228	111,862	113,431	114,166	115,772	117,748	120,291	122,465	124,966	126,678	129,336	132,015
Commercial	11,811	13,662	14,363	14,976	15,073	15,398	15,678	15,956	16,165	16,594	16,995	17,496
Wholesale	7	6	6	6	6	6	6	6	6	6	6	6
Industrial	39	47	49	50	50	50	52	51	43	42	42	42
Lighting	1,739	1,644	1,620	1,590	1,559	1,511	1,482	1,467	1,443	1,407	1,379	1,349
Irrigation	1,091	1,097	1,103	1,095	1,090	1,080	1,078	1,082	1,091	1,103	1,103	1,103
Total Direct	113,915	128,318	130,572	131,883	133,550	135,793	138,587	141,027	143,714	145,830	148,861	152,011

3.2 CUSTOMER ADDITIONS

Customer Additions	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022S	2023F
Residential	912	12,634	1,569	735	1,606	1,976	2,543	2,174	2,501	1,712	2,658	2,679
Commercial	106	1,851	701	613	97	325	280	278	209	429	401	501
Wholesale	-	(1)	-	-	-	-	-	-	-	-	-	-
Industrial	1	8	2	1	-	-	2	(1)	(8)	(1)	-	-
Lighting	(27)	(95)	(24)	(30)	(31)	(48)	(29)	(15)	(24)	(36)	(28)	(30)
Irrigation	17	6	6	(8)	(5)	(10)	(2)	4	9	12	-	-
Total Direct	1,009	14,403	2,254	1,311	1,667	2,243	2,794	2,440	2,687	2,116	3,031	3,150

4. NORMALIZED AFTER-SAVINGS USE PER CUSTOMER (UPC)

MWh/Customer	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022S	2023F
Residential	12.41	12.48	11.51	11.41	11.27	11.31	11.03	10.43	10.89	10.58	10.19	9.95

5. LOAD

5.1 NORMALIZED AFTER-SAVINGS LOAD

Energy (GWh)	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022S	2023F
Residential	1,229	1,353	1,296	1,298	1,296	1,320	1,313	1,266	1,347	1,330	1,304	1,301
Commercial	681	788	863	853	905	915	926	932	922	960	962	973
Wholesale	899	675	567	580	574	574	585	566	569	566	579	578
Industrial	291	352	381	380	373	363	403	495	441	472	579	575
Lighting	13	13	16	16	16	16	13	11	11	10	10	9
Irrigation	38	40	40	46	42	42	39	36	37	44	39	39
Net	3,151	3,222	3,163	3,174	3,206	3,230	3,278	3,306	3,328	3,381	3,473	3,476
Losses & Company Use	271	278	270	272	274	282	285	287	288	295	299	299
Gross	3,422	3,500	3,433	3,446	3,480	3,512	3,564	3,592	3,616	3,677	3,771	3,775
System Peak (MW)												
Winter Peak	723	698	693	685	755	714	682	732	731	685	782	786
Summer Peak	589	600	620	611	593	605	631	639	666	653	678	684

5.2 NORMALIZED AFTER-SAVINGS WHOLESALE LOAD

Wholesale (GWh)	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2021S	2022F
BCH Lardeau	6	6	6	6	6	8	8	7	6	6	7	7
BCH Kingsgate	5	5	5	5	5	5	5	5	5	4	5	5
City of Grand Forks	41	41	39	41	41	39	46	37	38	36	36	36
City of Nelson	80	83	81	83	80	86	88	84	82	86	79	78
City of Penticton	341	348	342	348	345	338	340	338	340	337	351	351
District of Summerland	95	98	94	97	98	98	99	95	99	97	101	101
City of Kelowna	332	94	-	-	-	-	-	-	-	-	-	-
Total	899	675	567	580	574	574	585	566	569	566	579	578

5.3 DSM (GWH) WITHOUT LOSSES

Energy (GWh)	2017	2018	2019	2020	2021	2022S	2023F
Demand Side Management	(28)	(31)	(26)	(26)	(30)	(28)	(56)

6. VARIANCES TO FORECAST

6.1 CUSTOMER COUNT VARIANCE

Customer Count	2016	2017	2018	2019	2020	2021
Actual						
Residential	115,772	117,748	120,291	122,465	124,966	126,678
Commercial	15,073	15,398	15,678	15,956	16,165	16,594
Wholesale	6	6	6	6	6	6
Industrial	50	50	52	51	43	42
Lighting	1,559	1,511	1,482	1,467	1,443	1,407
Irrigation	1,090	1,080	1,078	1,082	1,091	1,103
Total	133,550	135,793	138,587	141,027	143,714	145,830
Forecast						
Residential	115,758	116,031	117,774	120,405	124,076	124,603
Commercial	15,042	15,813	16,122	16,405	16,220	16,579
Wholesale	6	6	6	6	6	6
Industrial	49	50	50	51	57	59
Lighting	1,620	1,590	1,559	1,511	1,425	1,393
Irrigation	1,103	1,095	1,090	1,080	1,082	1,082
Total	133,578	134,585	136,602	139,459	142,865	143,721
Variance (customers)						
Residential	14	1,717	2,517	2,060	890	2,075
Commercial	31	(415)	(444)	(449)	(55)	15
Wholesale	0	0	0	0	0	0
Industrial	1	0	2	0	(14)	(17)
Lighting	(61)	(79)	(77)	(44)	18	14
Irrigation	(13)	(15)	(12)	2	9	21
Total	(28)	1,208	1,986	1,569	849	2,109
Variance (%)						
Residential	0.0%	1.5%	2.1%	1.7%	0.7%	1.6%
Commercial	0.2%	-2.7%	-2.8%	-2.8%	-0.3%	0.1%
Wholesale	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Industrial	2.0%	0.0%	3.8%	0.0%	-32.6%	-40.5%
Lighting	-3.9%	-5.2%	-5.2%	-3.0%	1.3%	1.0%
Irrigation	-1.2%	-1.4%	-1.1%	0.2%	0.8%	1.9%
Total	0.0%	0.9%	1.4%	1.1%	0.6%	1.4%

6.2 LOAD VARIANCE, NORMALIZED ACTUAL TO FORECAST

Energy (GWh)	2016	2017	2018	2019	2020	2021
Normalized						
Residential	1,296	1,320	1,313	1,266	1,347	1,330
Commercial	905	915	926	932	922	960
Wholesale	574	574	585	566	569	566
Industrial	373	363	403	495	441	472
Lighting	16	16	13	11	11	10
Irrigation	42	42	39	36	37	44
Net	3,206	3,230	3,278	3,306	3,328	3,381
Gross	3,480	3,512	3,564	3,592	3,616	3,677
Forecast						
Residential	1,367	1,353	1,280	1,349	1,326	1,255
Commercial	871	879	912	935	902	952
Wholesale	579	587	586	594	567	584
Industrial	393	407	379	385	453	537
Lighting	13	14	15	13	11	10
Irrigation	39	40	41	42	35	36
Net	3,262	3,282	3,213	3,319	3,294	3,374
Gross	3,540	3,559	3,485	3,602	3,602	3,664
Variance (GWh)						
Residential	(71)	(33)	33	(83)	21	75
Commercial	34	36	14	(3)	20	7
Wholesale	(5)	(13)	(1)	(28)	2	(18)
Industrial	(20)	(44)	24	110	(12)	(64)
Lighting	3	1	(2)	(2)	0	(0)
Irrigation	3	2	(2)	(6)	2	8
Net	(56)	(52)	65	(13)	34	8
Gross	(59)	(47)	79	(10)	14	13
Variance (%)						
Residential	-5.5%	-2.5%	2.5%	-6.6%	1.6%	5.6%
Commercial	3.8%	3.9%	1.5%	-0.4%	2.2%	0.8%
Wholesale	-0.8%	-2.3%	-0.2%	-5.0%	0.4%	-3.1%
Industrial	-5.3%	-12.3%	5.9%	22.2%	-2.7%	-13.6%
Lighting	16.3%	9.4%	-13.4%	-17.8%	2.1%	-2.8%
Irrigation	7.7%	3.9%	-5.2%	-16.7%	5.3%	17.9%
Net	-1.7%	-1.6%	2.0%	-0.4%	1.0%	0.2%
Gross	-1.7%	-1.3%	2.2%	-0.3%	0.4%	0.4%

6.3 NORMALIZED AFTER-SAVINGS ANNUAL PERCENT GROWTH

Energy (GWh)	2016	2017	2018	2019	2020	2021	2022S	2023F
Residential	1,296	1,320	1,313	1,266	1,347	1,330	1,304	1,301
Commercial	905	915	926	932	922	960	962	973
Wholesale	574	574	585	566	569	566	579	578
Industrial	373	363	403	495	441	472	579	575
Lighting	16	16	13	11	11	10	10	9
Irrigation	42	42	39	36	37	44	39	39
Net	3,206	3,230	3,278	3,306	3,328	3,381	3,473	3,476
Losses & Company Use	274	282	285	287	288	295	299	299
Gross	3,480	3,512	3,564	3,592	3,616	3,677	3,771	3,775
System Peak								
Winter Peak (MW)	755	714	682	732	731	685	782	786
Summer Peak (MW)	593	605	631	639	666	653	678	684

Growth Year over Year	2016	2017	2018	2019	2020	2021	2022S	2023F
Residential	0%	2%	-1%	-4%	6%	-1%	-2%	0%
Commercial	6%	1%	1%	1%	-1%	4%	0%	1%
Wholesale	-1%	0%	2%	-3%	1%	-1%	2%	0%
Industrial	-2%	-3%	11%	23%	-11%	7%	23%	-1%
Lighting	0%	0%	-17%	-17%	-2%	-11%	-2%	-1%
Irrigation	-9%	0%	-7%	-8%	4%	17%	-10%	0%
Net	1%	1%	1%	1%	1%	2%	3%	0%
Losses & Company Use	1%	3%	1%	0%	1%	2%	1%	0%
Gross	1%	1%	1%	1%	1%	2%	3%	0%
System Peak								
Winter Peak (MW)	10%	-5%	-4%	7%	0%	-6%	14%	0%
Summer Peak (MW)	-3%	2%	4%	1%	4%	-2%	4%	1%

Customer Count	2016	2017	2018	2019	2020	2021	2022S	2023F
Residential	115,772	117,748	120,291	122,465	124,966	126,678	129,336	132,015
Commercial	15,073	15,398	15,678	15,956	16,165	16,594	16,995	17,496
Wholesale	6	6	6	6	6	6	6	6
Industrial	50	50	52	51	43	42	42	42
Lighting	1,559	1,511	1,482	1,467	1,443	1,407	1,103	1,103
Irrigation	1,090	1,080	1,078	1,082	1,091	1,103	1,379	1,349
Total Direct	133,550	135,793	138,587	141,027	143,714	145,830	148,861	152,011

Growth Year over Year	2016	2017	2018	2019	2020	2021	2022S	2023F
Residential	1%	2%	2%	2%	2%	1%	2%	2%
Commercial	1%	2%	2%	2%	1%	3%	2%	3%
Wholesale	0%	0%	0%	0%	0%	0%	0%	0%
Industrial	0%	0%	4%	-2%	-16%	-2%	0%	0%
Lighting	-2%	-3%	-2%	-1%	-2%	-2%	-22%	0%
Irrigation	0%	-1%	0%	0%	1%	1%	25%	-2%
Total Direct	1%	2%	2%	2%	2%	1%	2%	2%

6.4 RESIDENTIAL UPC, NORMALIZED ACTUAL TO FORECAST

Residential UPC (MWh)	2019	2020	2021
After- Savings Normalized Actual UPC	10.43	10.89	10.58
Forecast	11.27	10.75	10.10
Variance	(0.84)	0.13	0.49
Variance (%)	-8.0%	1.2%	4.6%

6.5 WINTER PEAK , ACTUAL TO FORECAST

Winter Peak (MW)	2019	2020	2021
After- Savings Actual Peak	732	725	777
Forecast	764	737	748
Variance	(32)	(12)	29
Variance (%)	-4%	-2%	4%

Note: The peaks reflected in this table are the actual seasonal peaks are not normalized.

6.6 SYSTEM LOAD FACTOR

The following table shows annual after-savings gross load, peak load and load factor. The annual load factor is calculated as annual load ÷ peak hourly load x number of hours in a year (8,760).

Year	Energy (MWh)	Peak (MW)	Load Factor
2016	3,480,297	755	0.53
2017	3,511,820	714	0.56
2018	3,563,824	682	0.60
2019	3,592,459	732	0.56
2020	3,615,884	731	0.56
2021	3,676,926	685	0.61
2022S	3,771,436	782	0.55
2023F	3,774,844	786	0.55

Note: The peaks in this table represent annual peaks meaning they happened in the calendar year and are not the seasonal peaks.

Appendix A3

Load Forecast Methods

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1. LOAD FORECAST METHODS

This appendix describes FBC's load forecast methods on which the forecast in Section 3 of the Application is based.

In the figures provided in this appendix, the following three time frames are shown:

- Actual Years: Actual years are those for which actual data exists for the full calendar year[1]. For the 2023 Annual Review the latest calendar year for which full actual data exists is the 2021 calendar year.
- Seed Year: The Seed Year is the year prior to the first forecast year. The Seed Year is forecast based on the latest years of actual data available, and will be different than the original forecast for that year in the previous filing. For example, for this Application the Seed Year is 2022 (2022S) and the Seed Year forecast is based on the latest actual years, including 2021. As such, the 2022 Seed Year forecast in this Application will differ from the 2022 Forecast presented in the Annual Review for 2022 Rates, for which 2021 actual data was not available.
- Forecast Year(s): This is the year or years for which the forecast is being developed. This can be one year (in the case of the Annual Review) or a range of two or more years depending on the filing. In this Application, 2023 is the Forecast Year (2023F).

1.1 *WEATHER NORMALIZATION*

Electricity consumption is impacted by weather, particularly by temperature. For example, load requirements in an extremely cold winter month can be significantly higher than requirements in normal weather conditions in the same month, due to additional heating loads. As the load forecast is made under an assumption of normal weather, it is necessary to remove those extreme weather effects from the historical data. This is the first step in forecasting.

Statistical tests were made to check whether the residential, wholesale, commercial and irrigation loads were sensitive to temperature due to heating and cooling demands and whether the irrigation load was sensitive to the amount of precipitation[2]. The results from the regression for these four rate classes are shown below. The regressions result in high R^2 values for all seasons for the residential, wholesale and commercial[3] load classes; therefore these classes are normalized. The irrigation class shows a low R^2 value for the winter, summer and fall seasons; therefore, this class was not normalized.

[1] FBC's load forecast is developed using only full years of historical data. FBC requires the full year of load data in order to validate it, including the review of and potential adjustments to unbilled energy. For this reason partial year data is not used in forecasting.
[2] Industrial and lighting loads are typically insensitive to the weather.
[3] The commercial class data is normalized from 2014 to 2021 since a strong correlation was present in those years. All commercial data prior to 2014 is actual because it did not show a correlation to weather at that time.

Table A3-1: Residential Regression Table

Residential	Winter	Spring	Summer	Fall
Intercept	39,370	66,140	70,359	64,926
Slope HDD	172	109	-	92
Slope CDD	-	-	245	-
Adjusted R^2	0.72	0.76	0.84	0.77

Table A3-2: Wholesale Regression Table

Wholesale	Winter	Spring	Summer	Fall
Intercept	61,401	57,123	58,803	60,135
Slope HDD	58	47	-	36
Slope CDD	-	-	90	-
Adjusted R^2	0.91	0.92	0.85	0.91

Table A3-3: Commercial Regression Table

Commercial	Winter	Spring	Summer	Fall
Intercept	48,156	51,092	49,674	54,643
Slope HDD	24	16	-	(0)
Slope CDD	-	-	78	-
Adjusted R^2	0.58	0.54	0.68	0.53

Table A3-4: Irrigation Regression Table

Irrigation	Winter	Spring	Summer	Fall
Intercept	1,634	5,218	5,079	6,034
Slope HDD	(1)	(11)	-	(10)
Slope CDD	-	-	23	-
Adjusted R^2	0.04	0.76	0.45	0.43

Steps for weather (temperature) normalization are as follows:

1. Calculate monthly Heating Degree Days (HDD)[4] and Cooling Degree Days (CDD)[5] for the Penticton weather station.
2. Calculate 10-year HDD and CDD averages for each month of the year. These are used as the parameters of normal weather.
3. For each of the residential, wholesale and commercial classes, regress load on HDD or CDD on a seasonal basis. Four seasons were defined: winter (November to February), spring (March to May), summer (June to August) and fall (September to October). Thus all monthly load and degree day data for each season is used and four separate

[4] Heating degree-days for a given day are the number of Celsius degrees that the mean temperature is below 18 Celsius degrees.
[5] Cooling degree-days for a given day are the number of Celsius degrees that the mean temperature is above 18 Celsius degrees.

regressions are calculated for each class. The City of Kelowna (CoK) Event variables were included in the regressions to recognize the integration of the CoK in 2013 into the FBC direct customer base.

4. To normalize a month, e.g. February 2021:

   (a) obtain the month's HDD (or CDD) information from Environment Canada;

   (b) calculate the deviation from the 10-year average (2012-2021) HDD (CDD) as found in Step 2;

   (c) apply the regression slope obtained in Step 3 to this deviation to come up with a normalization adder; and

   (d) add the normalization adder to the month's load (residential, commerical or wholesale).

The general equation to normalize load requirements in month t is shown below.

$$Normalized\ Load_t = Load_t - HDD\ Slope_t \times (HDD_t - Normal\ HDD_t)$$

$$where\ HDD\ is\ Heating\ Degree\ Days\ and\ t = Spring, Fall\ and\ Winter$$

And

$$Normalized\ Load_t = Load_t - CDD\ Slope_t \times (CDD_t - Normal\ CDD_t)$$

$$where\ CDD\ is\ Cooling\ Degree\ Days\ and\ t = Summer$$

1.2 *LOAD FORECAST*

FBC forecasts energy requirements by customer class based on weather normalized historical loads. These are referred to as the "before-savings[6]" loads. DSM savings that are incremental to those embedded in historical loads (up to and including 2021) are also forecast for each customer class and subtracted from the before-savings loads to arrive at the "after-savings" loads. This section discusses the before-savings forecast load requirements for each of FBC's load classes.

1.2.1 Residential

The formula to forecast the expected before-savings residential load in year *t* is:

$$Before\ Savings\ Load_t = UPC_t \times Average\ Customer\ Count_t$$

where UPC (use per customer in MWh per customer per year) is before-savings.

[6] The term "before-savings" is used in the remainder of this section and refers to "before incremental savings after 2021".

The before-savings UPC was based on a 10-year historic trend of annual UPC values from 2012 to 2021. FBC reviews the forecast methods on an annual basis. As FBC found that there was a strong correlation, it therefore applied a 10-year trend.

Table A3-5: Results of UPC Trend Analysis

Regression	UPC
Start Year	2012
End Year	2021
R^2	0.84
Adjusted R^2	0.82
df	9
Intercept	414
Slope UPC	-0.20

Next, average customer count in year *t* is calculated as:

$$Average\ Customer\ Count_t = \frac{(Year\ End\ Count_t + Year\ End\ Count_{t-1})}{2}$$

The year-end customer count was based on the least squares regression model below.

$$Year\ End\ Customer\ Count_t = b_0 + b_1 \times Population_t$$

$Population_t$ is the population data supplied by BC Stats for the Company's direct service area.

Table A3-6: Results of Residential Regression

Regression	Residential
Start Year	2019
End Year	2021
R^2	1.00
Adjusted R^2	0.99
df	2
Intercept	(118,476)
Slope Population	0.88

The residential class represented 39.3 percent of the net load in 2021.

1.2.2 Commercial

The expected before-savings commercial load in year *t* is forecast based on the provincial GDP supplied by the CBOC. The relationship was estimated from the following equation.

$$Before\ Savings\ Load_t = (b_0 + b_1 \times GDP_t + b_2 \times CoK\ Event_t) + FBC\ EV\ DC\ Fast\ Chargers$$

The CoK_t is a binary variable for the City of Kelowna integration event in 2013. Coefficients b0, b1 and b2 are obtained from an ordinary least squares (OLS) regression analysis on the 2007 to

2021 data. The FBC EV DCFCs are Electric Vehicle Direct Current Fast Chargers serviced by FBC which are added to the forecast. The commercial class represented 28.4 percent of the net load in 2021.

Table A3-7: Results of Commercial Regression

Regression	Commercial
Start Year	2007
End Year	2021
R^2	0.99
Adjusted R^2	0.99
df	14
Intercept	123,607
Slope GDP	3
Slope CoK Event	132,847

1.2.3 Wholesale

The Company forecasts the wholesale load based on load surveys from the wholesale customers. For this forecast, FBC received surveys from all the wholesale customers except one. This customer was contacted multiple times but did not respond. Since there was no response, FBC kept their load at 2021 levels. FBC then summed the wholesale customers' forecasts to calculate the before-savings wholesale load forecast. This approach recognizes that in the near to medium term, the wholesale customers themselves are best able to forecast their load growth based on their knowledge of their customer mix, load behaviors, development projects with associated load requirements, etc. The wholesale class represented 16.7 percent of the net load in 2021.

1.2.4 Industrial

The before-savings industrial load is the sum of forecasts supplied by those individual customers who responded to the load survey and, for customers who did not respond, escalation of the customer's load in the preceding year by the CBOC forecast GDP growth rates for the industrial sector the customer is in. 81 percent of FBC's industrial customers responded to the surveys, accounting for 90 percent of 2021 load.

FBC assumes no new industrial customers in the current forecast unless there is a confirmed commitment from an industrial customer. FBC works with key account managers to identify new customers and existing customers with expansion plans that have commited contracts that are being added to the system. The key account managers work with the new customers directly and relay the load requirements to the forecasting group. The industrial class represented 14.0 percent of the net load in 2021.

1.2.5 Irrigation

The before-savings irrigation load forecast uses a five-year average so that the extreme weather events such as those that occurred in 2021 are included in the forecast but do not overly influence it. The irrigation class represented 1.3 percent of the net load in 2021.

1.2.6 Lighting

The before-savings lighting load uses the 2021 actuals due to the variability in the load primarily due to streetlight LED replacement programs which reduced the loads from 2018 to 2021. The lighting class represented 0.3 percent of the net load in 2021.

1.2.7 Demand Side Mangment (DSM) Savings

FBC forecasts load reductions resulting from its DSM programs.

The forecast of DSM savings is consistent with the Company's approved 2019-2022 DSM Plan. DSM measures are grouped into applicable programs that are then added to produce the three primary sector (residential, commercial & industrial) annual plan savings targets. Finally, the annual sector targets beginning with the Seed Year are converted into a cumulative time series, and disaggregated into the customer rate classes and commensurate system loss reductions.

1.3 *PEAK DEMAND FORECAST*

The peak demand forecast is produced by taking the 10-year average (2012-2021) of historical peak data. The historical peak data is escalated by the gross load growth rate before it is averaged to account for the growth of demand on the FBC system. Self-generating customers are removed from the historical load data since the underlying trends that impact other loads do not apply. Seasonal peaks were used for both the winter and the summer. The 12 monthly peaks, as well as the seasonal peaks, were then escalated by the annual load growth rates in the forecast period to produce forecast monthly peaks. The winter peak and the summer peak are assumed to replace monthly peaks in December and July, respectively.

The after DSM peak forecast was calculated by subtracting DSM capacity savings forecast from the before DSM peak forecast for each month in each year.

Appendix B
PRIOR YEAR DIRECTIVES

No.	Decision Page No.	Directive No.	Reference	Description / Details	Status	Section in this Application
G-8-17 – FBC ANNUAL REVIEW FOR 2017 RATES						
1.	21	6	Upper Bonnington Old Units Refurbishment Project	The Panel directs FBC to report in each of its annual review applications during the remainder of the PBR term the following information on the UBO Refurbishment project: • The status of both the UBO Refurbishment project as a whole and of the individual units, including a comparison of the project timeline provided in the current Applicaton to any updated project timeline as at the time of filing each annual review application. • Updated cost estimates and cost descriptions compared to the cost estimates and scope descriptions provided in the current Application, including explanations for any variances/changes to the cost estimates or project scope. • Actual costs incurred to date on the UBO Refurbishment project as a whole and on each individual unit as at the time of filing each annual review application. • Final actual refurbishment costs at the completion of each unit, including a description of the scope of work completed relative to the conditions found and against the cost estimate.	Complete (Final Report filed in this Annual Review)	Appendix B2
G-165-20 AND G-166-20 – FEI AND FBC MULTI-YEAR RATE PLAN FOR 2020 THROUGH 2024						
2.	75	24	General Flow-through Deferral Account	The Panel directs [FBC] to provide a detailed analysis of the individual forecast variances recorded in the Flow-through deferral account in each Annual Review.	Ongoing during the MRP term	Section 12.4.2.1

No.	Decision Page No.	Directive No.	Reference	Description / Details	Status	Section in this Application
3.	87	32	Efficiency Carry-Over Mechanism	Therefore, the Panel determines the following process for the handling of an ECM application: 1. An ECM can be applied for at any time in the last three years of the MRPs, either in advance or following the action or initiative being undertaken. 2. For proposed activities where identifiable savings are expected to extend beyond the term of the MRP, FortisBC is to file an ECM proposal describing the initiative, its timing, costs and benefits and savings. 3. Parties will have the opportunity to review and comment on the proposal and the BCUC will determine whether to approve the ECM proposal (an Approved ECM Initiative). FortisBC must submit details of continued savings annually under an Approved ECM Initiative as part of the Annual Review process. The net savings will be shared equally between ratepayers and the Utilities will carry forward past the end of the MRP for a maximum period of three years.	No approved ECM initiatives to report on	n/a
4.	99	35	SAIDI and SAIFI major events	The Panel also directs FBC to include a discussion of major events relevant to the SAIDI and SAIFI results in future Annual Review materials.	Ongoing during the MRP term	Section 13
5.	99-100		SQI Informational Indicators	In addition to the SQIs, the Panel approves the following informational indicators for the Utilities: • Customer Satisfaction Index (measures overall customer satisfaction) – FEI and FBC. • Average Speed of Answer (average number of seconds to answer emergency and non-emergency calls) – FEI and FBC. • Generator Forced Outage Rate (percent of time a generating unit is removed from service due to component failure or other events) – FBC only. • Interconnection Utilization (percent of time that an interconnection point was available and providing electrical service to wholesale customers) – FBC only. The Utilities are directed to report on these informational indicators along with the SQIs as part of the Annual Review process.	Ongoing during the MRP term	Section 13

No.	Decision Page No.	Directive No.	Reference	Description / Details	Status	Section in this Application
6.	118	42	System Operations, Integrity and Security Expenditures	The Panel directs FBC to provide the following information related to System Operations, Integrity and Security expenditures in its future revenue requirements applications over the term of the Proposed MRPs: 1. A breakdown and explanation of both annual and cumulative variances between forecast/actual and formula O&M related to System Operations, Integrity and Security expenditures, which quantify the variances attributable to the following areas: • Tree management; • Generation dam safety; • Network operations apprentice program; • Cyber security; • Data analytics; and • Any other significant factors or miscellaneous items. 2. A description of how FBC is prioritizing its System Operations, Integrity and Security expenditures.	Ongoing during the MRP term	Section 6.2.1
7.	131	49	Forecast Capital Expenditures	The Panel directs FortisBC to file an updated forecast of the 2023 to 2024 capital expenditures in the 2023 Annual Review.	Complete	Section 7.2.1
G-42-21 – FBC ANNUAL REVIEW FOR 2020 AND 2021 RATES						
8.	21		COVID-19 Customer Recovery Fund Deferral Account	The Panel approves the following deferral account requests: f. Recording of the COVID-19 incremental costs and related savings from 2020 and 2021 into the previously approved COVID-19 Customer Recovery Fund deferral account, as discussed in Section 12.2.1 of the Application.	Status of COVID-19 exogenous factor treatment provided in this Application	Section 12.2.1
G-374-21 – FBC ANNUAL REVIEW FOR 2022 RATES						
9.	32	7	Wholesale Customer Load Forecast	The Panel directs FBC to provide details of any efforts it has undertaken to improve the accuracy of its forecasts of wholesale customer load in the 2023 Annual Review, including the results of such efforts.	Complete	Section 3.4.3
10.	32	8	EV Charging Updates	The Panel directs FBC to include in future Annual Review filings an update on its EV DCFC charging stations' costs and revenues for the previous fiscal year along with a forecast of costs and revenues for the test period.	Ongoing	Section 6.3.4

Appendix B2

FortisBC Inc.

Upper Bonnington Old Units Refurbishment Project

Final Report

August 2022

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1. PROJECT STATUS

1.1 *PROJECT BACKGROUND*

On January 20, 2017, the British Columbia Utilities Commission (BCUC) approved capital expenditures related to the Upper Bonnington (UBO) Old Units Refurbishment (UBO Refurbishment Project, or the Project) in Order G-8-17. Directive 6 of Order G-8-17 required FBC to file specific information on the Project's updated scope, progress and costs as part of FBC's future annual review applications. Specifically, the BCUC directed FBC to provide the following information about the progress of the Project:

- The status of both the UBO Refurbishment Project as a whole and of the individual units, including a comparison of the Project timeline provided in the [Annual Review for 2017 Rates] Application to any updated Project timeline as at the time of filing each annual review application.
- Updated cost estimates and cost descriptions compared to the cost estimates and scope descriptions provided in the [Annual Review for 2017 Rates] Application, including explanations for any variances/changes to the cost estimates or Project scope.
- Actual costs incurred to date on the UBO Refurbishment Project as a whole and on each individual unit as at the time of filing each annual review application.
- Final actual refurbishment costs at the completion of each unit, including a description of the scope of work completed relative to the conditions found and against the cost estimate.[1]

The UBO Refurbishment Project involved the refurbishment of generating Units 1-4 (the Old Units), which are over 100 years old, in order to extend their lives for an additional 20 years or more. The Project also reduced the safety and environmental risks associated with failures of the aged equipment.

FBC submits the following final report regarding the UBO Refurbishment Project in compliance with Directive 6 of Order G-8-17, including final Project costs (Final Report).

The Project scope of work was completed and closed out in Q4 2021. The four generating units and associated equipment have been put into commercial operation and are performing well.

The Project successfully eliminated or reduced the safety and environmental risks previously associated with operating the plant.

[1] Order G-8-17, Appendix A, page 21.

With regard to the major environmental and safety accomplishments achieved during Project execution, FBC reports that it followed the Environmental Management Plan (EMP) developed in 2017 and the Project had no reportable environmental incidents. Further, the Project accumulated approximately 160 thousand hours without a lost time incident. The majority of the effort on the Project was internal FBC labour, with approximately 19 thousand hours supplied externally. While the COVID-19 pandemic presented challenges during the second half of the Project, the policies and procedures implemented by FBC minimized the risk of infection and Project interruption.

1.2 *WORK COMPLETED SINCE AUGUST 2021 STATUS REPORT*

The following is a brief summary of the work completed since the August 2021 status report filed as Appendix B2 to FBC's Annual Review for 2022 Rates application.

Balance of Plant

The scope of the balance of plant work evolved as the Project progressed and included the following:

Floor modifications – As equipment was removed, the concrete bases were demolished and floor repairs were completed. The plant floor loadings, drawings, demarcation, procedures and site signage updates were completed.

Ventilation access walkway – With the removal of the old switchgear concrete structure, both wall and floor repairs were required. The switchgear concrete structure provided access to plant ventilation systems; with the removal of this concrete, new access walkways and ladders were designed and installed.

Water wheel excitation decommissioning – The water wheel exciters and associated equipment were removed and the intakes were plugged with concrete. The holes through the generator and turbine floors were capped with steel plates. The exciter rheostats and buss were removed and the rheostat room was repurposed for plant equipment storage.

Units 2 and 3

Minor work was completed on Units 2 and 3 which was intentionally delayed until site conditions were preferable in 2021. The work included painting, hazardous materials removal, and the rotor oil leak repair on Unit 3.

Project Close

The Project was closed in Q4 2021 with all equipment and plant transferred back to generation operations.

2. PROJECT SCHEDULE

The following table is updated to show the final completion dates for each unit as well as the balance of plant work.

Table B2-1: Milestone Summary

Milestone	Planned Completion Date	Actual Completion Date	Status
Engineering			
Mechanical Components – Machining and Fabrication Specifications	Q4, 2017	Q4, 2017	Complete
All Units Detailed Engineering	Q1, 2018	Q1, 2018	Complete
Balance of Plant Engineering	Q3, 2020	Q4, 2020	Complete
Procurement of All Major Mechanical/Electrical	Q2, 2020	Q2, 2020	Complete
Construction			
Refurbishment of Unit 3	Q4, 2017	Q4, 2017	Complete
Refurbishment of Unit 4	Q4, 2018	Q4, 2018	Complete
Refurbishment of Unit 1[1]	Q4, 2020	Q4, 2019	Complete
Refurbishment of Unit 2[1]	Q4, 2019	Q4, 2020	Complete
U3 Oil Leak Deficiency Repair	Q1, 2021	Q2, 2021	Complete
Balance of Plant Work	Q2, 2021	Q3, 2021	Complete
Closeout	Q3, 2021	Q4, 2021	Complete

Note:

[1] *Units 1 and 2 construction years were changed from the original schedule to gain efficiencies by removing equipment while operating a live plant.*

2.1 *SCHEDULE SUMMARY*

The rotor oil leak repair work on Unit 3 delayed portions of the Balance of Plant scope of work from Q2 2021 to Q3 2021. The work completed on Units 2 and 3 as outlined above in Section 1.2 was completed in parallel with the Balance of Plant work, and the Project was closed in Q4 2021.

While some of the work was re-scheduled around sequencing concerns and operational constraints, the overall Project duration was as originally planned.

3. PROJECT COSTS

The following table outlines the final Project expenditures.

Table B2-2: Cost Summary

Description	Application/ Control Budget	Final Costs	Variance	Variance
	($000s)			(%)
Unit 4	6,634	8,058	1,424	21%
Unit 3	4,079	6,529	2,450	60%
Unit 2	5,641	6,606	965	17%
Unit 1	8,050	8,287	237	3%
Balance of Plant	860	1,657	797	93%
Subtotal - Construction	25,264	31,137	5,873	23%
Cost of Removal	1,880	1,840	-40	-2%
Project Contingency	3,771	-	-3,771	-
Subtotal - Construction & Removal	30,916	32,997	2,062	7%
AFUDC	867	1,174	307	35%
Total Project Cost	31,783	34,151	2,369	7%

3.1 *PROJECT COST SUMMARY*

The UBO Refurbishment Project was approved with a Class 4 capital cost estimate of $31.783 million in as-spent dollars (including $0.867 million of AFUDC and $1.880 million of removal costs). The Project's cost estimate was at an AACE Class 4 estimate class because of the difficulty in defining the full scope without dismantling the units. Final Project costs (including $1.174 million of AFUDC and $1.840 million of removal costs) are $34.151 million, which is 7 percent or approximately $2.4 million over the control budget. This is well within the typical accuracy range of an AACE Class 4 cost estimate as stated in AACE Recommended Practice 69R-12, Cost Estimate Classification System – As Applied in Engineering, Procurement, and Construction for the Hydropower Industry. As reported in the August 2020 status report, this approximately $2.4 million variance resulted primarily from higher than planned costs to rewind the generators and to refurbish the concealed turbine components.

The cost variances in each Project category are further described below.

Units 1-4 – These variances are explained in the August 2020 status report. In 2021, both Units 2 and 3 painting scope of work that had been delayed was completed. Unit 3 rotor oil leak repair work was completed for a final cost of approximately $0.252 million. These completed scopes are included in the final costs presented in Table B2-2.

Balance of Plant Work – The balance of plant work scope of work was completed with an unfavourable variance of $0.797 million. The Balance of Plant scope of work evolved as the

Project progressed. The installation of new equipment and removal of old equipment within an operating facility presented unanticipated challenges that were not able to be defined during the planning stage. This variance is primarily due to the extra effort required to remove equipment and cabling which was not expected to contain asbestos and the additional civil structural scopes, as well as the floor modifications required to facilitate the new plant equipment.

Cost of Removal – The forecast total for cost of removal is $1.840 million, which represents a favourable variance of $0.040 million.

Contingency – Project contingency has been utilized to offset the variances that were encountered among the different Units.

AFUDC – The total cost for AFUDC is $1.174 million, which represents an unfavourable variance of $0.307 million due to the higher overall Project costs.

3.2 *PROJECT SCOPE CHANGE SUMMARY*

Throughout the Project, FBC made adjustments to address unforeseen challenges and issues which were either not considered or not accessible during the planning stage. These adjustments totalled approximately $2.015 million and were explained in the August 2020 status report.

4. CONCLUSION

The UBO Refurbishment Project is complete and has successfully eliminated or reduced the safety and environmental risks previously associated with operating the plant. The Project maintained schedule and returned the Units to commercial service within the year planned. The final Project costs were well within the typical accuracy range of an AACE Class 4 cost estimate and totalled $34.151 million. This approximately $2.4 million increase was required to complete scope and ensure the units could operate safely for 20 years or more, as originally planned.

Appendix C
PROJECTS AND MARKET REPORT

Market Report: Gas and Electric Transmission and Distribution Cost Impacts 2020-2024

May 2022

The Engagement

FortisBC has engaged Wood Mackenzie Supply Chain Consulting to provide a market report detailing how market factors have impacted and are anticipated to impact North American utility spend between 2020 and 2024. Wood Mackenzie is a global research and consulting firm that provides energy clients with data, analytics, and insights that they rely on for their decision making. Wood Mackenzie Supply Chain Consulting (SCC), formerly PowerAdvocate, utilizes proprietary cloud-based software solutions and bespoke consulting services to enable our clients to leverage data analysis and assist them in navigating an ever-changing marketplace.

Market dynamics over the last two years have created significant inflationary pressures across both materials and services. This market report is specific to two portfolios: electric transmission and distribution (T&D) and gas T&D capital expenditures at Canadian utilities, with labour specific to British Columbia, Canada. In both portfolios, market escalation has been observed since FortisBC's initial Multi-Year Rate Plan (MRP) filing (Quarter 1, 2020 through Quarter 1, 2022). This report also includes a forecast of potential impacts from Quarter 2, 2022 through Quarter 4, 2024.

Qualifications

Wood Mackenzie Supply Chain Intelligence is a suite of cloud-based software solutions that includes a product, Cost Intelligence, which enables our clients to identify market-based risks and opportunities. Cost Intelligence includes thousands of cost models and indices that enable users to understand what a project or item should cost in a dynamic market. Wood Mackenzie Cost Intelligence models were developed to support the energy market. The Wood Mackenzie team starts with industry specifications, technical drawings, supplier 10ks, and other industry information to develop detailed items that tie cost inputs to dynamic market indices. Those indices are then weighted and loaded on the cloud-based platform. The items are combined into categories and sub-categories that reflect clients spend profiles, or specific capital project expenditures.

Methodology

North American Gas and Electric Utility Cost Models

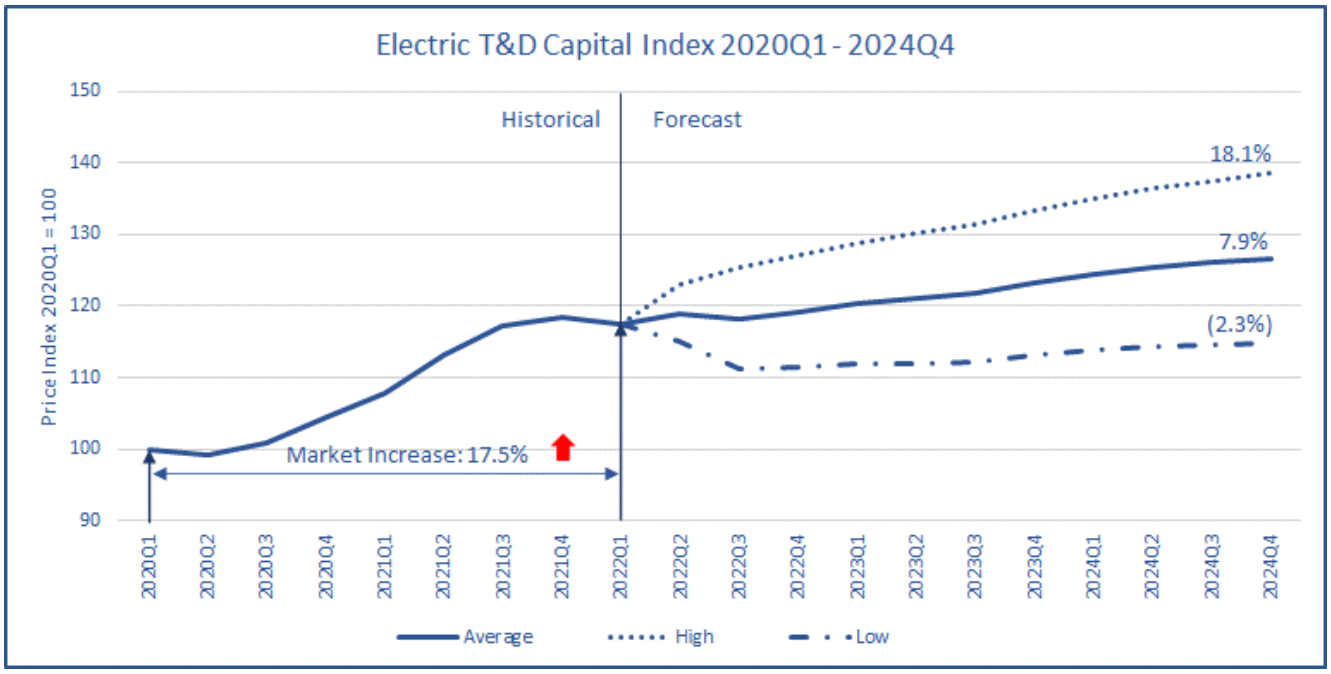
Wood Mackenzie built two customized cost models – Electric Transmission and Distribution and Gas Transmission and Distribution. Each cost model is built from aggregated spend from utilities across North America and over $550M (CAD) in total spend. The models apply indices to spend at an item level and roll up to sub-category, category, and facility level. Each model incorporates over 150 indices tracked monthly by Wood Mackenzie.

Customization for British Columbia Specific Labour Pool

British Columbia (BC) has a unique labour pool and, where appropriate, the models incorporate indices specific to BC, particularly around trade labour and any other labour activities specific to the BC province.

Market Insights

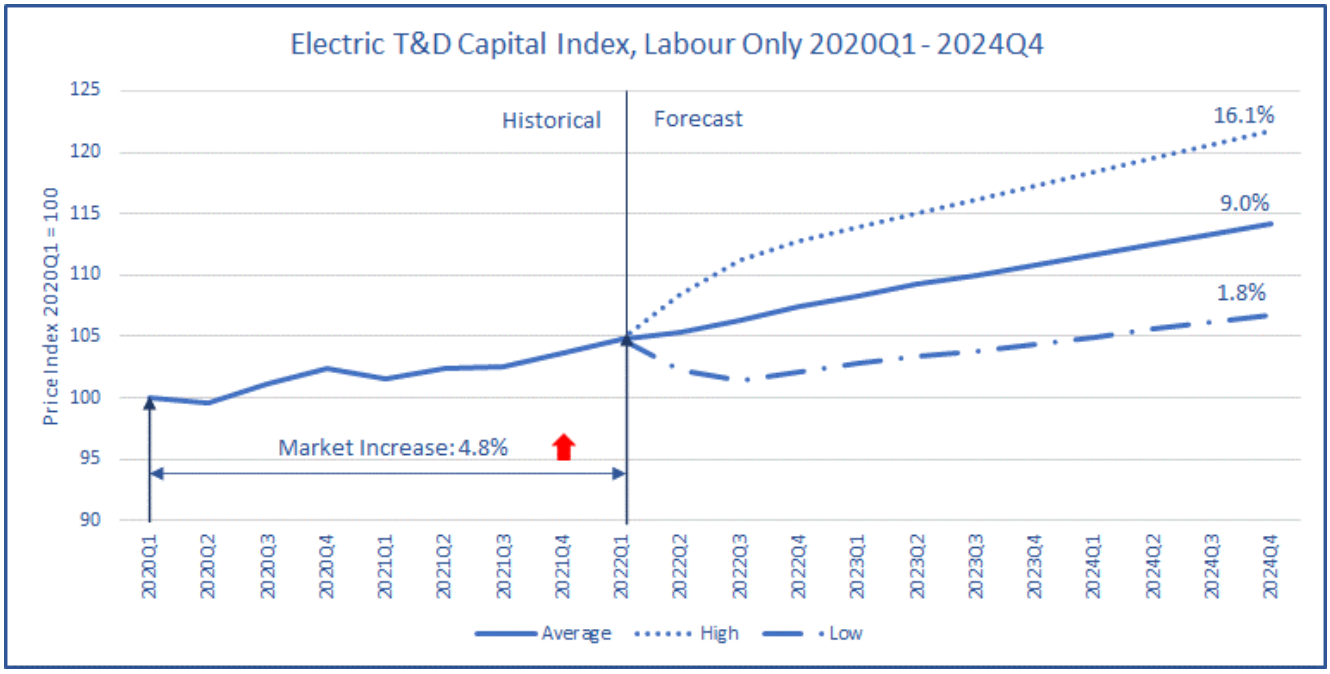
Electric Transmission and Distribution 2020Q1-2024Q4



*This graph includes an aggregate of multiple indices, including both labour and material cost components.
**Forecasted percentage increases or decreases are based on index 2022Q1 = 100

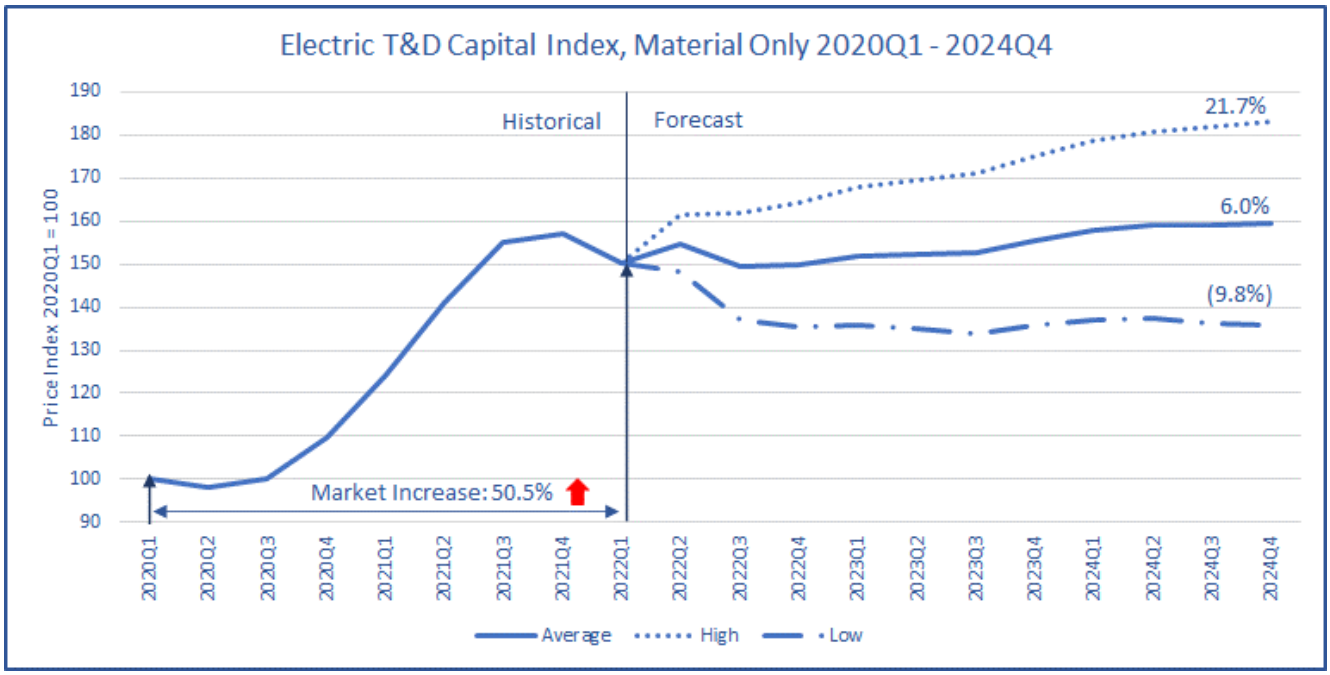
Since execution of FortisBC's MRP (Q1 2020 – Q1 2022), market factors have caused an escalation in capital costs for electric T&D of 17.5%. Forward-looking forecasts for Q1 2022 – Q4 2024 average 7.9%. Table 1 shows the ten most impactful commodities and services in the electric T&D model, and their individual escalations since the beginning of the MRP. Sharp increases in steel and aluminum prices starting in Q3 2020 drove escalations through Q3 2021. Prices of steel and aluminum have leveled off since Q4 2022 which is reflected in the forecast through 2024. The total market split for Electric T&D between labour and materials is 65% and 35% respectively. Labour costs are expected to continue to rise, while material costs level out.

Electric Transmission and Distribution - Labour 2020Q1-2024Q4



**Forecasted percentage increases or decreases are based on index 2022Q1 = 100

Electric Transmission and Distribution - Material 2020Q1-2024Q4



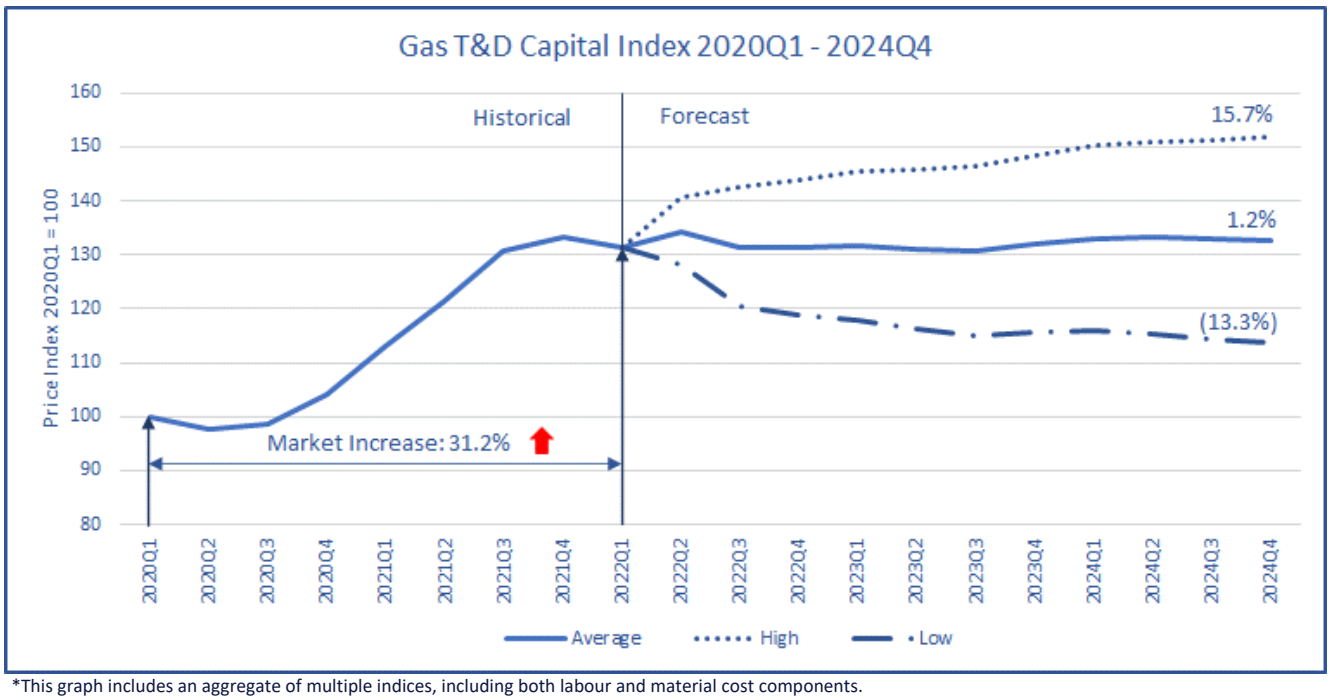
**Forecasted percentage increases or decreases are based on index 2022Q1 = 100

Table 1. Electric T&D High-impact Commodities and Services

Electric T&D High Impact Commodities and Services	Q1 2020 – Q2 2022 (%)
AHE: Mechanical and Electrical Trades, Basic Construction Union Wages, BC	1.5
AHE: Construction, Private Compensation, BC	10.8
ECEC: Benefits, Private Construction	3.3
SPM: Steel, Hot-Rolled Coil	117.3
PPI: Cement, Canada	(3.4)
AHE: Heavy Equipment Operator, Basic Construction Union Wages, BC	2.6
AWE: Repair and Maintenance, BC	4.3
SPM: Aluminum, High Grade	83.2
PPI: Springs and Wire Products, Canada	42.2
IM: Transmission Conductor	160.4

AHE: Average Hourly Earnings, Employer Costs for Employee Compensation, SPM: Spot Price Metal, IPPI: Producer Price Index, AWE: Average Weekly Earnings, IM: Industry Margin

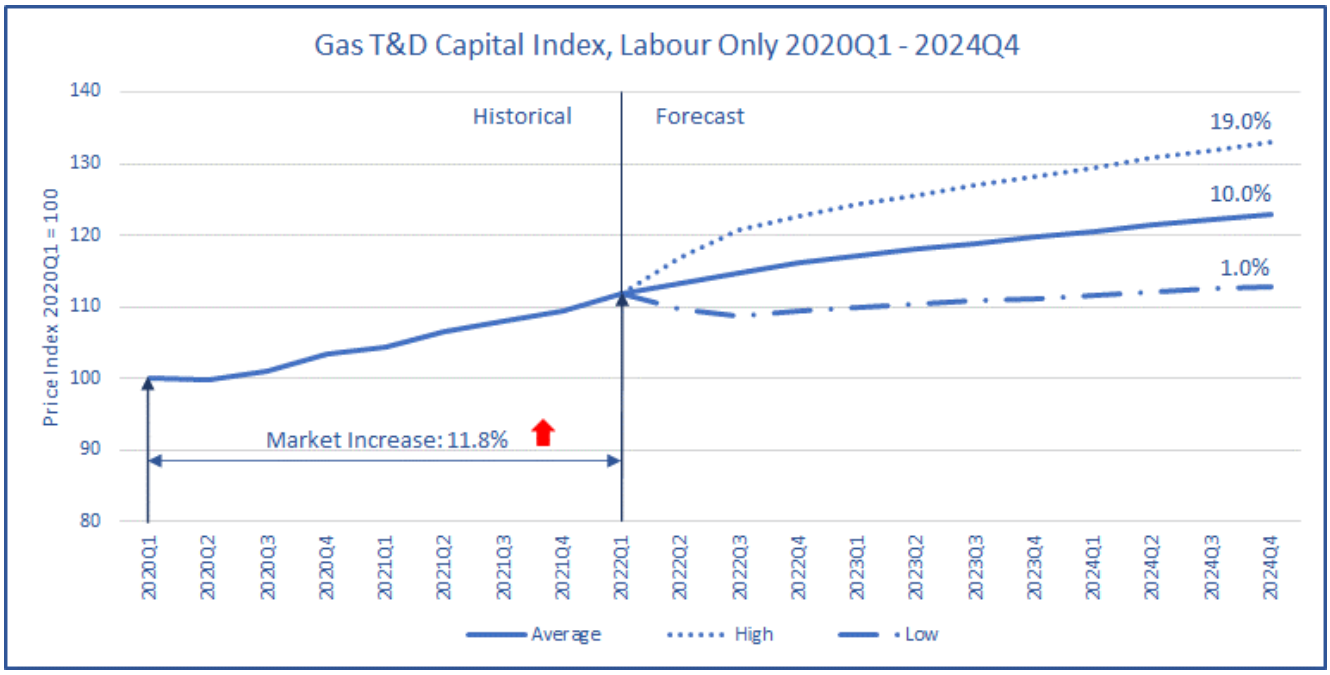
Gas Transmission and Distribution 2020Q1 – 2024Q4



*This graph includes an aggregate of multiple indices, including both labour and material cost components.
**Forecasted percentage increases or decreases are based on index 2022Q1 = 100

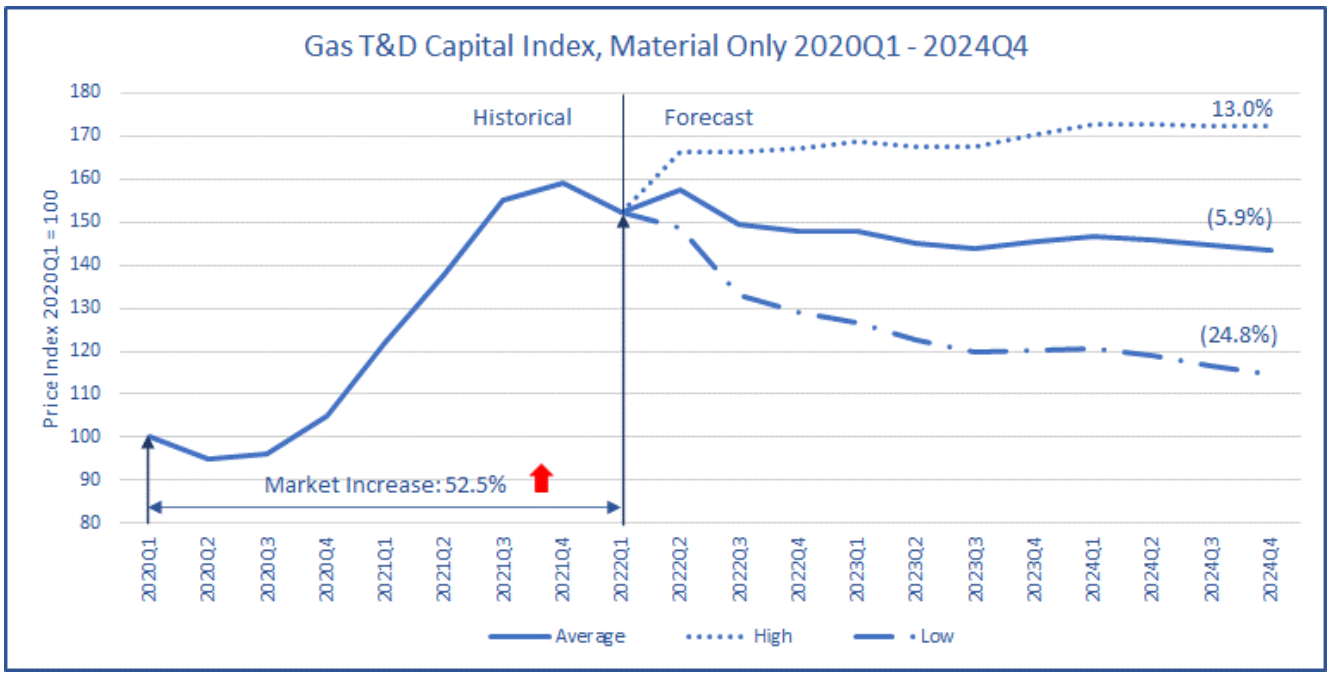
Since execution of FortisBC's MRP (Q1 2020 – Q1 2022), market factors have caused an escalation in capital costs for gas T&D of 31.2%. Forward-looking forecasts for Q1 2022 – Q4 2024 average 1.2%. Table 2 shows the ten most impactful commodities and services in the gas T&D model, and their individual escalations since the beginning of the MRP. Sharp increases in steel and aluminum prices starting in Q3 2020 drove escalations through Q3 2021. Prices of steel and aluminum have leveled off since Q4 2022 which is reflected in the forecast through 2024. The total market split for Gas T&D Construction between labour and materials is 44% and 56% respectively. Labour costs are expected to continue to rise, while material costs are expected to drop slightly, driven by declining steel prices.

Gas Transmission and Distribution - Labour 2020Q1 – 2024Q4



**Forecasted percentage increases or decreases are based on index 2022Q1 = 100

Gas Transmission and Distribution - Material 2020Q1 – 2024Q4



**Forecasted percentage increases or decreases are based on index 2022Q1 = 100

Table 2. Gas T&D High-impact Commodities and Services

Gas T&D High Impact Commodities and Services	Q1 2020 – Q2 2022 Escalation (%)
AHE: Construction, Private, Compensation, BC	10.8
SPM: Steel Plate, Cut-to-Length	173.7
SPM: Steel, Hot-Rolled Coil	117.3
PPI: Hand and Edge Tools	2.7
PPI: Commercial and Industrial Machinery and Equipment Rental	(2.2)
AHE: Professional, Scientific and Technical Services, BC	11.6
SPM: Steel Plate, Coiled	117.3
AHE: Architectural and Finishing Trades, Basic Construction, BC	1.4
AHE Manufacturing, BC	9.8
PPI: Metal Building and Construction Materials, Canada	51.1

AHE: Average Hourly Earnings, SPM: Spot Price Metal, PPI: Producer Price Index

Pre-MRP Market Escalations

The market conditions for both electric and gas T&D vary significantly from the five years prior to the execution of the MRP. Table 3 uses the same models as above to observe the market between Q1 2015 through Q4 2019. Two years (2015 and 2019) experienced a decrease in market price, and the total escalations over this period were 7.6% and 7.5% for electric T&D and gas T&D, respectively.

Table 3. Annual Market Adjustments for Electric and Gas T&D

Year Q1 – Q4	Electric T&D Market Change (%)	Gas T&D Market Change (%)
2019	(0.2)	(3.6)
2018	1.0	4.5
2017	1.8	1.2
2016	4.1	3.6
2015	(1.7)	(3.5)

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Appendix C2

Project Descriptions for Forecast Growth and Sustainment Capital

August 2022

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1. INTRODUCTION

In this appendix, FBC provides descriptions of growth and sustainment capital projects over $1 million.

As described in Section 7 of the Application, FBC's growth capital is divided into the following portfolios:

1. Transmision Growth;
2. Distribution Growth; and
3. New Connects.

FBC's sustainment capital is divided into the following portfolios:

1. Generation;
2. Transmission Sustainment;
3. Stations Sustainment;
4. Distribution Sustainment; and
5. Telecommunications.

The projects over $1 million in each of these categories are described below.

2. GROWTH CAPITAL

2.1 *TRANSMISSION GROWTH*

Regular Transmission Growth capital consists of discrete projects as dictated by transmission system capacity requirements based on forecast load for adequate supply during periods of peak demand and adverse weather conditions.

The table below shows the original spend profile of the projects greater than $1 million in this category during the MRP term, as provided in the MRP Application.[1]

[1] MRP Application, Section 3.4.1.1.1, Table C3-23, pp. C-82 and C-83.

Table C2-1: FBC Transmission Growth Capital Expenditures on Projects Greater than $1 million in MRP Application ($000s)

	2020	2021	2022	2023	2024
Sexsmith 2nd Transformer Addition	4,633	-	-	-	-
Summerland Transformer Replacement	539	2,063	-	-	-
Beaver Park Substation Upgrade	-	-	2,740	5,195	-
DG Bell 2nd Transformer Addition	-	-	-	-	1,086

The table below shows the updated forecast spend profile of the projects greater than $1 million in this category during the MRP term.

Table C2-2: Updated FBC Transmission Growth Capital Expenditures on Projects Greater than $1 million ($000s)

	2020	2021	2022	2023	2024
Sexsmith 2nd Transformer Addition	5,311	66	-	-	-
Beaver Park Substation Upgrade	-	636	4,936	6,223	-
Duck Lake 2nd Transformer Addition	-	-	-	-	1,088

Each of these projects is described further below.

- **Sexsmith Second Transformer Addition:** Peak load on the existing 32 MVA Sexsmith T1 transformer was forecast to exceed nameplate capacity in 2020. In order to continue to maintain the current levels of reliability and meet the planning criteria for this area of Kelowna, a second transformer was installed and put into service at the Sexsmith substation in 2020. The actual costs of this project were approximately $5.3 million with the bulk of capital expenditures occurring in 2020.
- **Summerland Transformer Replacement:** The existing 20 MVA Summerland substation transformer supplies one of two wholesale delivery points to the District of Summerland municipal utility. Due to anticipated new commercial development in Summerland, peak load at this wholesale delivery point was previously forecast to exceed 95 percent of the contract demand limit during the MRP term. Since the most recent load forecast projects that peak load will not exceed this threshold until 2026, no project expenditures are planned during the MRP term. FBC will continue to engage with the District of Summerland municipal utility to discuss options to increase wholesale capacity. This project is thus not included in Table C2-2.
- **Beaver Park Substation Upgrade:** This project is driven by load growth in the Trail area and equipment condition issues as the BEP T1 transformer tap changer cannot be adequately maintained. The project seeks to rebuild the Beaver Park substation on an expanded station footprint. To meet planning criteria and continue to provide a reliable supply, the existing transformer will be replaced, and a second transformer will be installed. The estimated total project cost including direct overhead is approximately $11.8

million. The total project costs have increased since the MRP Application filing in 2019 due to several factors, including archaeological requirements and increases in engineering, materials and construction costs. Commodity cost increases have placed significant pressure on materials.

- **Duck Lake Second Transformer Addition:** This project is driven by significant development occurring in the area served by the Duck Lake substation. FBC planning studies indicate that a second distribution transformer is required at Duck Lake to maintain the current level of reliability and support distribution contingency planning criteria. As the pace and scale of development has exceeded what was anticipated when the MRP Application was filed, this project has now been advanced ahead of the DG Bell project described below. The estimated cost of this project is $5.3 million; however, the cost could increase further as a result of potential commodity cost increases impacting the cost of materials.
- **DG Bell Second Transformer Addition:** FBC planning studies indicate that a second distribution transformer is required at DG Bell to maintain the current level of reliability and support distribution contingency planning criteria. This project has been deferred from the original 2024-25 construction schedule to accommodate the Duck Lake Second Transformer Addition. This project is now planned for 2025-26 with an estimated in-service date of 2026. This project is thus not included in Table C2-2.

2.2 *DISTRIBUTION GROWTH*

Similar to its transmission system, FBC evaluates distribution system capacity on an annual basis, based on the projected loads. FBC's Distribution Growth capital includes two ongoing programs, small (planned) growth projects and unplanned growth projects. Larger individual distribution growth projects are also included.

The table below shows the original spend profile of the projects greater than $1 million in this category during the MRP term, as provided in the MRP Application.[2]

Table C2-3: FBC Distribution Growth Capital Expenditures on Projects Greater than $1 million in MRP Application ($000s)

	2020	2021	2022	2023	2024
DG Bell Feeder 4 Addition	1,970	-	-	-	-

The table below shows the updated forecast spend profile of the projects greater than $1 million in this category during the MRP term.

[2] MRP Application, Section 3.4.1.1.2, Table C3-24, pp. C-83 and C-84.

Table C2-4: Updated FBC Distribution Growth Capital Expenditures on Projects Greater than $1 million ($000s)

	2020	2021	2022	2023	2024
DG Bell Feeder 4 Addition	-	26	1,870	-	-
Huth CoP 13KV Supply	1,219	62	-	-	-

Each of these projects is described further below.

- **DG Bell Feeder 4 Addition:** This project was deferred due to the timing of City of Kelowna road construction from 2020 to 2022; however, the total actual project cost is lower than forecast in the MRP Application.
- **Huth CoP 13KV Supply:** This project was added in 2020. The project was required to ensure that FBC continues to meet the terms of its Wholesale Agreement with the City of Penticton at the Huth substation Point of Delivery.

2.3 *NEW CONNECTS*

There are no projects over $1 million that have been completed or are planned to be completed during the MRP term.

3. SUSTAINMENT CAPITAL

3.1 *GENERATION SUSTAINMENT*

FBC operates and maintains four generating facilities with a total of 15 units. FBC regularly monitors its infrastructure to ensure it meets industry standards and guidelines, complies with regulations, and operates safely to minimize risk to the public and employees. FBC's Generation capital is grouped into four capital programs: (i) Hydraulic Dam Structures; (ii) Generating Equipment; (iii) Generation Auxiliary Equipment; and (iv) Buildings and Structures.

The table below shows the original spend profile of the projects greater than $1 million in this category during the MRP term, as provided in the MRP Application[3].

Table C2-5: FBC Generation Sustainment Capital Expenditures on Projects Greater than $1 million in MRP Application ($000s)

	Category	2020	2021	2022	2023	2024
Concrete Structures Rehabilitation	Hydraulic Dam Structures	685	821	979	1,128	1,019
LBO Spillway Gates Refurbishment	Hydraulic Dam Structures	1,467	1,396	-	-	-

[3] MRP Application, Section 3.4.1.2.1, pp. C-84 to C-88.

	Category	2020	2021	2022	2023	2024
Other Gates Upgrades	Hydraulic Dam Structures	481	100	414	241	545
Dam Safety Instrumentation	Hydraulic Dam Structures	715	765	-	-	806
Guarding of Rotating Parts	Hydraulic Dam Structures	194	324	458	295	287
UBO Unit 6 Turbine Runner Replacement	Generating Equipment	-	35	582	2,035	-
Generator Excitation System and Control Systems	Generating Equipment	-	67	556	556	-
Generator Thrust Bearing Cooling System	Generating Equipment	247	271	295	198	198
Dewatering and Drainage Systems	Generation Auxiliary Equipment	116	349	349	349	349
Station Service Upgrade	Generation Auxiliary Equipment	333	495	286	286	300
COR Annex Building Replacement	Buildings and Structures	-	-	-	198	1,606

The table below shows the updated forecast spend profile of the projects greater than $1 million in this category during the MRP term.

Table C2-6: Updated FBC Generation Sustainment Capital Expenditures on Projects Greater than $1 million ($000s)

	Category	2020	2021	2022	2023	2024
Concrete Structures Rehabilitation	Hydraulic Dam Structures	715	745	1,128	651	1,061
LBO Spillway Gates Refurbishment	Hydraulic Dam Structures	1,436	2,893	-	-	-
Dam Safety Instrumentation	Hydraulic Dam Structures	896	287	1,059	100	100
Rehabilitation of Dam Stability Anchors	Hydraulic Dam Structures	78	442	392	326	-
UBO Unit 6 Turbine Runner Replacement	Generating Equipment	-	22	501	1,395	2,085
Generator Excitation System and Control Systems	Generating Equipment	-	271	344	485	836
Dewatering and Drainage Systems	Generation Auxiliary Equipment	126	217	655	1,166	222

	Category	2020	2021	2022	2023	2024
Station Service Upgrade	Generation Auxiliary Equipment	298	577	834	512	260
COR Annex Building Replacement	Buildings and Structures	4	4	186	200	1,606

Each of these projects is described in further detail below:

- **Concrete Structures Rehabilitation Project:** This is a continuation of the program started in 2014 to address requirements of the BC Dam Safety Regulation and deterioration of concrete structures. The cost for this project is $0.332 million lower than forecast in the MRP Application due mainly to reduced scope at the Lower Bonnington Dam as safety issues are restricting access to lower areas of the construction scaffold in the tailrace during unit start-up. FBC is working on designing a solution to this issue.
- **Lower Bonnington Dam (LBO) Spillway Gates Refurbishment Project:** This project was completed in 2021 at a higher cost than forecast due to complexities encountered during construction and the implementation of a monorail system for the installation of stoplogs that was not considered initially.
- **Other Gates Upgrade Project:** This project is now forecast to cost less than $1 million due to FBC implementing a simpler solution for strengthening the LBO intake superstructure. This project is thus not included in Table C2-6.
- **Dam Safety Instrumentation Project:** This project addresses the requirement in section 19(1) of the BC Dam Safety Regulation for instrumentation to adequately monitor the dam and the area surrounding or adjacent to the dam. The project began in 2018 and includes the installation of dam monitoring systems at FBC's plants. FBC has thus far completed the installation of dam safety instrumentation at LBO and UBO and will complete the installation of dam safety instrumentation at South Slocan (SLC) in 2022. The higher costs are primarily due to higher drilling costs. The installation of the dam safety instrumentation at Corra Linn (COR) has been delayed with only the engineering being planned to occur in 2023-2024.
- **Guarding of Rotating Parts Project:** This project is now forecast to cost less than $1 million due to a reduction in scope. The original forecast included installing guards on spillway and intake gates, but during detail design, more effective administrative and operational methods were developed and implemented which have resulted in cost reductions. This project is thus not included in Table C2-6.
- **Rehabilitation of Dam Stability Anchors:** This project was included in the Other Hydraulic Dam Structures Projects category in the MRP Application, as at the time of filing it was expected to cost less than $1 million. However, the scope of work has increased from $0.302 million to $1.238 million due to damage to the anchors' heads being more extensive and the number of anchor heads that required repairs being higher than initially anticipated; the degree of the anchor head damage could only be established while

inspecting the anchors which are located on the overflow spillway. The rehabilitation of the LBO dam stability anchors will be competed in 2022. Rehabilitation of the COR dam stability anchors will commence in 2023 and will complete in 2025.

- **Upper Bonnington Dam (UBO) Unit 6 Turbine Runner Replacement Project:** This project includes the replacement of the UBO Unit 6 turbine runner that has reached the end of its service life. Work on this project was accelerated to mitigate the anticipated delays in the global supply chain due to the COVID-19 pandemic. The estimated cost of this project is approximately $1.445 million higher than originally forecast due to the costs of the runner being higher. The expected in-service date is December 2024.
- **Generator Excitation System and Control System Replacement Project:** This project addresses the replacement of some of the generator excitation systems beginning in 2022 with Unit 6 at UBO. The updated cost of this project is approximately $0.765 million higher due mainly to higher costs with the procurement of the control and excitation systems.
- **Generator Thrust Bearing Cooling System Upgrade Project:** This project is now forecast to cost less than $1 million as FBC has implemented a better designed solution that has resulted in cost savings. This project is thus not included in Table C2-6.
- **Dewatering and Drainage Systems Rehabilitation Project:** This project was budgeted based on costs including rehabilitation of pipes valves and other components of the dewatering and drainage systems. During detail design it was discovered that this solution was not feasible and a new solution was designed and is being implemented which is based on a pump in gate design that has an increased cost of $0.690 million. The first system is planned to be put in service at SLC in 2023 and engineering for the next plant will occur in 2024.
- **Station Service Upgrade Project:** This project includes upgrading the protection system of FBC's station service system and neutral grounding in order to address safety hazards, replacement of station service transformers that have reached the end of their service life and other small station service improvements. The estimated cost of this project is $0.186 million higher due to the need to address deficiencies related to LBO powerhouse grounding and bonding issues that were uncovered while doing investigations in 2021.
- **Corra Linn Annex Building Replacement Project:** FBC has decided to start the preliminary engineering in 2022 and is planning to complete the project in 2024.

3.2 *TRANSMISSION SUSTAINMENT*

Transmission Sustainment expenditures are required to proactively manage the condition and integrity of FBC's transmission line facilities, manage the risk to employees and public safety, and maintain an acceptable level of service for customers.

The table below shows the original spend profile of the projects greater than $1 million in this category during the MRP term, as provided in the MRP Application[4].

Table C2-7: FBC Transmission Sustainment Capital Expenditures on Projects Greater than $1 million in MRP Application ($000s)

	2020	2021	2022	2023	2024
30 Line Rehabilitation	1,100	-	-	-	-
30, 32, 19 Lines Right of Way	647	651	658	656	652

The table below shows the updated forecast spend profile of the projects greater than $1 million in this category during the MRP term.

Table C2-8: Updated FBC Transmission Sustainment Capital Expenditures on Projects Greater than $1 million ($000s)

	2020	2021	2022	2023	2024
30 Line Rehabilitation	1,087	91	-	-	-
30, 32, 19 Lines Right of Way	458	637	652	652	648

Each of these projects is described in further detail below:

- **30 Line Rehabilitation between the South Slocan and Coffee Creek Substations:** This project included expenditures for structural stabilization of the transmission line, based on the 2018 condition assessment, including stubbing poles and replacing poles and cross-arms. The project was completed as planned in 2020.
- **30, 32 and 19 Line Right of Way Improvements:** The scope of this multi-year project involves acquiring an additional right of way predominantly upslope of the existing right of way for 30 Line (Nelson to Coffee Creek Substation), 32 Line (Creston to Crawford Bay), and 19 Line (Slocan Valley) and clearing the additional right of way to reduce the number of tree-related outages. Portions of these lines are in steep terrain. Of FBC's 72 transmission lines, tree contacts on 30 Line account for 17 percent of the transmission related outages. Tree contacts on 32 Line and 19 Line each account for approximately 8 percent of FBC's transmission related outages. These projects are in progress, with FBC implementing land owner agreements to widen the right of way.

3.3 *STATIONS SUSTAINMENT*

FBC's substation sustainment capital expenditures are driven by a combination of time-based and condition-based scheduling. Currently, FBC employs a substation Computerized Maintenance Management System (CMMS) which tracks basic equipment data and condition information for FBC's substation assets and is used to assist in scheduling maintenance tasks.

[4] MRP Application, Section 3.4.1.2.2, pp. C-89 and C-90.

The table below shows the original spend profile of the projects greater than $1 million in this category during the MRP term, as provided in the MRP Application.[5]

Table C2-9: FBC Stations Sustainment Capital Expenditures on Projects Greater than $1 million in MRP Application ($000s)

	2020	2021	2022	2023	2024
AS Mawdsley Tranformer Replacement	-	-	-	-	3,802
Trout Creek Transformer Replacement	2,263	-	-	-	-
Kaleden Transformer Replacement	-	-	-	-	2,716
Salmo Station Upgrade	3,718	7,154	-	-	-
Fruitvale Station Upgrade	-	-	-	-	3,802

The table below shows the updated forecast spend profile of the projects greater than $1 million in this category during the MRP term.

Table C2-10: Updated FBC Stations Sustainment Capital Expenditures on Projects Greater than $1 million ($000s)

	2020	2021	2022	2023	2024
Trout Creek Transformer Replacement	153	2,660	1,568	-	-
Keremeos 2nd Transformer Addition	-	-	-	543	2,700
Salmo Station Upgrade	4,778	5,143	-	-	-
Fruitvale Station Upgrade	-	-	-	1,087	7,021

Each of these projects is described in further detail below:

- **AS Mawdsley Transformer Replacement:** FBC is now planning to file a Certificate of Public Convenience and Necessity (CPCN) application for this project as the cost is forecast to be above the $20 million materiality threshold. This project is thus not included in Table C2-10.
- **Trout Creek Transformer Replacement:** This project is driven by asset condition, as the transformer is 52 years old and uses the most unreliable Load Tap Changer (LTC) in the FBC fleet (Pioneer TC546). The acetylene levels and a barrel collecting the excess oil moving from the main tank to LTC indicated a cracked LTC terminal board. The project is currently in execution with an estimated in-service date of 2022. Increases in project costs are due to delays related to the lands purchase and ALR approval, along with significant additional work related to other end of life station equipment. Further

[5] MRP Application, 3.4.1.2.3, Tables C3-34 and C3-35, pp. C-91 to C-93.

investigation of the station after the MRP proceeding revealed that the entire station was in a similar condition as the transformer which resulted in a rebuild of the station.

- **Keremeos Second Transormer Addition:** This project is driven by asset condition. The Keremeos transformer has a 48 year old LTC that is not functioning. Based on the resulting operational challenges with the control of customer voltages, this transformer replacement is a high priority.
- **Kaleden Transformer Replacement:** This project has been deferred until after the end of the MRP term to accommodate the previously unforeseen Keremeos Transformer Replacement project. The existing Keremeos transformer presents a larger risk at this time, but planning remains underway for replacement of the Kaleden transformer in 2025-26. This project is thus not included in Table C2-10.
- **Salmo Station Upgrade:** This project was driven by equipment condition issues and aging infrastructure at the Salmo and Ymir substations. The project rebuilt the Salmo substation on the existing station footprint and decommissioned the Ymir substation. The Ymir substation customers were permanently transferred to the Salmo substation. Construction began in 2020 and was completed in 2021. The total cost of this project was $9.9 million. The overall total project cost was less than forecast due primarily to lower actual costs for the distribution and transmission line work. The replacement of the Salmo Station 13 kV Switchgear was also included in this project.
- **Fruitvale Station Upgrade:** This project is driven by equipment condition issues and aging infrastructure at the Fruitvale and Hearns substations. The Hearns single phase transformer units are approximately 72 years old, and the Fruitvale metal-clad switchgear is approximately 55 years old; this equipment is at risk of failing. The project seeks to rebuild and relocate the Fruitvale substation, while decommissioning the Hearns substation. The Hearns substation customers would be permanently transferred to the Fruitvale substation. The existing Fruitvale substation footprint is too small to accommodate the rebuild, and land will need to be acquired for the upgrade. To meet planning criteria and continue to provide a reliable supply to the Fruitvale area, the existing transformer will be replaced, and a second transformer will be installed. The estimated total project cost including direct overhead is $12.5 million. FBC forecasts spending $1.1 million in 2023, $7.0 million in 2024, and $4.4 million in 2025 with an estimated in-service date of 2025. The total project costs have increased since the MRP Application due to several factors, including land acquisition requirements and increases in engineering, material and construction costs.

3.4 *DISTRIBUTION SUSTAINMENT*

There are no projects over $1 million that have been completed or are planned to be completed during the MRP term.

3.5 TELECOMMUNICATIONS SUSTAINMENT

FBC's telecommunications system is an integral component in the protection relaying system, remedial action schemes, substation operations and control, and generation dispatch systems. The system requires ongoing investment to replace aging or failed systems for safe and reliable operation of the system and to ensure business needs continue to be met.

The table below shows the original spend profile of the projects greater than $1 million in this category during the MRP term, as provided in the MRP Application[6].

Table C2-11: FBC Telecommunications Sustainment Capital Expenditures on Projects Greater than $1 million in MRP Application ($000s)

	Category	2020	2021	2022	2023	2024
Backbone Transport Technology Migration	Systems Upgrades and Replacements	-	-	937	953	-
SCADA System Replacement	Systems Upgrades and Replacements	-	1,086	2,192	2,188	1,086
VHF Radio System Replacement	Systems Upgrades and Replacements	-	-	548	875	-

The table below shows the updated forecast spend profile of the projects greater than $1 million in this category during the MRP term.

Table C2-12: Updated FBC Telecommunications Sustainment Capital Expenditures on Projects Greater than $1 million ($000s)

	Category	2020	2021	2022	2023	2024
Backbone Transport Technology Migration	Systems Upgrades and Replacements	-	-	-	841	853
SCADA System Replacement	Systems Upgrades and Replacements	-	-	-	543	1,080
VHF Radio System Replacement	Systems Upgrades and Replacements	-	-	-	-	540

Each of these projects is described in further detail below:

- **Backbone Transport Technology Migration:** This project will replace FBC's existing SONET network with a new high-speed data network supporting all present and anticipated future applications needed to provide safe and reliable service. The project, which was originally forecast to start in 2022, is now expected to commence in 2023.
- **SCADA System Replacement Project:** This project was planned to start in 2021; however, due to limited resources the business analysis was not initiated until late 2021,

[6] MRP Application, Section 3.4.1.2.5, pp. C-99 to C-101.

resulting in delays to determine the best SCADA solution. The estimated cost of this project has decreased to approximately $6 million.

- **VHF Radio System Replacement Project:** The existing FBC Electric VHF Radio system is at the end of its service life (>20 years old) and the technology is obsolete. Parts are still available but are becoming more difficult to source and the legacy technology is difficult to support as new hires are not trained or experienced with the legacy technology. New 2-way radio technologies bring significant benefits with respect to sharing of channels, ease of maintenance, superior coverage and ability to send data in addition to voice. In 2024, the first stages of the VHF radio replacement project are expected to start, with the project continuing into 2025.

Appendix D
DRAFT ORDER

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British Columbia
Utilities Commission

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Vancouver, BC Canada V6Z 2N3
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TF: 1.800.663.1385
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ORDER NUMBER
G-xx-xx

IN THE MATTER OF
the *Utilities Commission Act*, RSBC 1996, Chapter 473

and

FortisBC Inc.
Annual Review for 2023 Rates

BEFORE:
E. B. Lockhart, Panel Chair
C. M. Brewer, Commissioner
A. Pape-Salmon, Commissioner

on Date

ORDER

WHEREAS:

A. On June 22, 2020, the British Columbia Utilities Commission (BCUC) issued its Decision and Order G-166-20 approving a Multi-Year Rate Plan (MRP) for 2020 through 2024 (2020-2024 MRP Decision) for FortisBC Inc. (FBC). In accordance with the 2020-2024 MRP Decision, FBC is to conduct an annual review (Annual Review) process to set its rates for each year;

B. By letter dated June 28, 2022, FBC proposed a regulatory timetable for the Annual Review of its 2023 rates;

C. By Order G-193-22 dated July 15, 2022, the BCUC established the regulatory timetable for the Annual Review of FBC's 2023 rates, which included FBC filing its Annual Review materials, intervener registration, one round of information requests, a workshop, FBC's responses to undertakings at the workshop, and written final and reply arguments;

D. On August 5, 2022, FBC submitted its materials for the Annual Review for 2023 Rates Application (Application). In the Application, FBC requests a 3.99 percent rate increase over 2022 rates, effective January 1, 2023, among other things; and

E. The BCUC has reviewed the Application, evidence and arguments filed in the proceeding and makes the following determination.

NOW THEREFORE pursuant to sections 59 to 61, 89 and 99 of the *Utilities Commission Act*, for the reasons stated in the decision issued concurrently with this order, the BCUC orders as follows:

1. FBC is approved to recover the 2023 revenue requirement and resultant rate change on an interim basis, effective January 1, 2023, as filed in the Application and subject to any adjustments identified by FBC during

the regulatory process and from any directives or determinations made by the BCUC in its decision on the Application. Rates will remain interim pending the outcomes of Stage 1 of the BCUC's current generic cost of capital (GCOC) proceeding and FBC's 2023-2027 Demand Side Management (DSM) Plan proceeding.

2. The level of forecast growth, sustainment and other capital to be incorporated in rates for the years 2023 and 2024, as set out in Section 7.2.1, is approved.

3. FBC is approved to:

    a. Create a rate base deferral account for the 2023 Joint Pole Use Audit and amortize the deferral account over five years commencing January 1, 2023; and

    b. Amortize the existing COVID-19 Customer Recovery Fund Deferral Account over three years commencing January 1, 2023.

4. FBC is approved to cease reporting on the COVID-19 Customer Recovery Fund Deferral Account.

5. Directive 6 of Order 42-21 is varied as follows: "FBC is approved to record COVID-19 incremental costs and related savings from 2020 and 2021 into the Flow-through deferral account".

6. Directive 2 of Order G-83-14 is varied as follows: "Approval is granted until such time as FBC no longer has an exemption to prepare and file its financial statements in accordance with US GAAP or is no longer reporting under US GAAP for financial reporting purposes".

7. FBC is directed to file with the BCUC as a compliance filing, within 15 days of the issuance of this order, amended tariff pages and finalized financial schedules for 2023, in accordance with the terms of this order.

DATED at the City of Vancouver, in the Province of British Columbia, this (XX) day of (Month Year).

BY ORDER

(X. X. last name)
Commissioner

FBC 2024 ANNUAL REVIEW OF RATES
EXHIBIT B-2

Sarah Walsh
Director, Regulatory Affairs

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August 4, 2023

British Columbia Utilities Commission
Suite 410, 900 Howe Street
Vancouver, BC
V6Z 2N3

Attention: Patrick Wruck, Commission Secretary

Dear Patrick Wruck:

Re: FortisBC Inc. (FBC)

Multi-Year Rate Plan for 2020 through 2024 approved by British Columbia Utilities Commission (BCUC) Order G-166-20 (MRP Plan)

Annual Review for 2024 Rates

In accordance with the MRP Plan and BCUC Order G-191-23 setting out the Regulatory Timetable for FBC's Annual Review, FBC hereby attaches its Annual Review for 2024 Rates Application materials.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC INC.

Original signed:

Sarah Walsh

Attachments

cc (email only): Registered Interveners in the FBC Annual Review for 2023 Rates proceeding.

FORTIS BC™

FORTISBC INC.

Multi-Year Rate Plan for 2020 through 2024

Annual Review for 2024 Rates

August 4, 2023

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1. APPROVALS SOUGHT, OVERVIEW OF THE APPLICATION AND PROPOSED PROCESS

1.1 INTRODUCTION

FortisBC Inc. (FBC or the Company) files this Application in compliance with British Columbia Utilities Commission (BCUC) Order G-166-20, which approved a Multi-Year Rate Plan (MRP or the Plan) for FBC for the years 2020 to 2024. In accordance with the MRP, an annual review process is required to set rates for each year of the MRP.

The MRP provides stable levels of O&M funding and includes service quality indicators (SQIs) to monitor the maintenance of service quality. The approved Earnings Sharing Mechanism (ESM), set out in Section 10, aligns the incentive properties of the Plan between customers and the Company.

As explained in Section 10 of the Application, FBC proposes to distribute $2.396 million pre-tax ($1.749 million after-tax) in earnings sharing to customers in 2024.

The proposed rates for 2024 flowing from the forecasts and approved formulas set out in the Application, including returning the actual 2022 earnings sharing to customers, result in a 4.83 percent rate increase from 2023 rates. The increase is primarily due to an increase in power purchase expense (PPE), followed by an increase in income tax expense.

In the subsections below, FBC sets out the approvals it is seeking and provides an overview of the requirements for the annual review process. This is followed by a discussion of FBC's 2022 formula O&M savings and the productivity initiatives that FBC is developing. Finally, FBC provides a summary of its proposed revenue requirements and rate changes for 2024 and a summary of the SQI results. These matters are addressed in more detail in subsequent sections of the Application.

1.2 APPROVALS SOUGHT

With this Application, FBC requests BCUC approval for the following pursuant to sections 59 to 61 of the *Utilities Commission Act* (UCA):

1. Approval to recover the 2024 revenue requirement and resultant rate change on a permanent basis, effective January 1, 2024, as filed in the Application and subject to any adjustments identified by FBC during the regulatory process and from any directives or determinations made by the BCUC in its decision on the Application.
2. Creation of the following rate base deferral accounts, as described in Section 7.6:
    - 2025 Multi-year Rate Plan (MRP) Application deferral account, with the amortization period to be determined in a future proceeding;

- 2024 Mandatory Reliability Standards (MRS) Audit deferral account, with an amortization period of three years, commencing January 1, 2024;
- PST Rebate on Select Machinery and Equipment deferral account, with an amortization period of one year, commencing January 1, 2024;
- BC Cost of Living Credit deferral account, with an amortization period of one year, commencing January 1, 2024; and
- Climate Change Operational Adaptation (CCOA) Plan deferral account, with an amortization period of four years, commencing January 1, 2024.

A draft order is included in Appendix C.

1.3 REQUIREMENTS FOR THE ANNUAL REVIEW

On page 167 of the MRP Decision, the BCUC set out its expectations for the Annual Review component of the MRP. For reference, the table below sets out each requirement and FBC's response or where it is addressed in the Application.

Table 1-1: Annual Review Requirements

Item	Description	Response or Reference
1	Review of the current year projections and the upcoming year's forecast. For further clarity, these items are listed below:	See items 1(a) to 1(f) below
1(a)	Customer growth, volumes and revenues;	Section 3
1(b)	Year-end and average customers, and other cost driver information including inflation;	Section 2
1(c)	Expenses, determined by the indexing formula plus items forecast annually;	Section 6
1(d)	Capital expenditures (as provided for by the capital forecast), plus other items forecast annually;	Section 7
1(e)	Plant balances, deferral account balances and other rate base information and depreciation and amortization to be included in rates; and	Sections 7 and 12
1(f)	Projected earnings sharing for the current year and true-up to actual earnings sharing for the prior year.	Section 10
2	Identification of any efficiency initiatives that the Utilities have undertaken, or intend to undertake, that require a payback period extending beyond the MRP period with recommendations to the BCUC with respect to the treatment of such initiatives.	FBC has not identified any efficiency initiatives with a payback beyond the end of the MRP period
3	Review of any exogenous events that the Company or stakeholders have identified that should be put forward to the BCUC for review.	Section 12.2
4	Review of the Utilities' performance with respect to SQIs. Bring forward recommendations to the BCUC where there have been a "sustained serious degradation" of service.	Section 13

Item	Description	Response or Reference
5	Assess and make recommendations with respect to any SQIs that should be reviewed in future Annual Reviews.	FBC does not have any recommendations at this time
6	Reporting on the Innovation Fund status.	Not Applicable for FBC
7	Assess and make recommendations to the BCUC on potential issues or topics for future Annual Reviews.	FBC does not have any recommendations at this time

1.4 FORMULA O&M SAVINGS AND PRODUCTIVITY INITIATIVES

1.4.1 Overview of 2022 Formula O&M Savings

For 2022, FBC achieved formula O&M savings in addition to meeting the embedded productivity improvement factor in the O&M formula. Total formula O&M savings before earnings sharing were approximately $3.7 million, excluding the COVID-19 pandemic approved exogenous factor credit for net O&M cost reductions of approximately $1.0 million.

Of the approximate $3.7 million in formula O&M savings realized in 2022, approximately $3 million are due to labour savings, including overtime. The remaining savings are due to a variety of factors including reduced postage and printing costs from paperless billing and general timing of non-labour expenditures. While some of the savings are one-time in nature (e.g., required time to fill vacancies from turnover), some of the savings are expected to continue into the future, recognizing that cost pressures in the future may offset the savings.

FBC will continue to pursue productivity improvements to achieve savings beyond the productivity improvement factor as it seeks to manage its business needs and cost pressures resulting from its evolving and challenging operating environment.

1.4.2 Productivity Initiatives

As described in FBC's Annual Review for 2022 Rates, in 2021, FBC and FortisBC Energy Inc. (together FortisBC) initiated a working group consisting of senior managers and directors from different parts of the organization that is responsible for reviewing and identifying productivity initiatives. Following is a summary of these productivity initiatives.

1. **Field Operations Improvements:** A review of the meter reading routes was undertaken and updated to achieve optimized routes, resulting in reduced overtime and increased employee safety. In addition to optimizing meter reading routes, range extenders continue to be added to reduce the number of manual meter reads required, resulting in reduced travel time for meter readers and consistent, reliable meter readings for customers. Additionally, Operations is undertaking work to accurately map meters to their corresponding transformer which has operational benefits. Mapping the transformer-to-meter relationship provides accurate capacity information which can be used to determine

where EV charging load growth is and where it can be added to utilize existing infrastructure. Another benefit is that customer outage mapping improves the ability for technicians to more effectively and quickly troubleshoot system trouble calls.

2. **Use of Unmanned Aerial Vehicles (UAVs - Drones):** FBC's contract resources that are tasked with performing transmission line condition assessments continue to rely on the use of UAVs to aid in the completion of this work. Although UAVs have not eliminated the need for human resources to complete condition assessment work, primarily due to limitations on the operation of UAVs beyond visual line of sight, they have allowed FBC to reduce the need for follow-up bucket truck inspections to confirm deficiencies that cannot be fully assessed from a ground-based inspection. Additionally, FBC has equipped its Operations crews with small drones that allow for visual inspections during trouble or outage events where ground access may be difficult or restricted. FBC will continue to monitor industry developments regarding the use of UAVs for supporting utility operations.

3. **Data Analytics:** This is an initiative to centralize the Company's data sources coupled with a suite of analytic tools to analyze and use the data to inform decision-making. FortisBC uses data to inform decision making, but its current data is spread across dozens of disparate systems. Data is often siloed within departments and the volume, variety, and velocity of data coming into FortisBC is increasing. It can be difficult and time consuming to gather, clean, and filter the data needed to create useful information. As part of the solution, Enterprise Analytics creates a data fabric atop core FortisBC source and storage systems to facilitate advanced analytics opportunities. It addresses key barriers by integrating existing data into a single, scalable platform to deliver easily accessible and reliable data. It also simplifies connecting data assets to reduce cost and effort to create reports that can be easily updated and enables automation of reporting. Enterprise Analytics enables improvement in key performance indicators selected by each business area, and provides enhanced data quality, and work efficiency. Benefits are realized from shared information and sharing of insight across business units. Additionally, quality assurance is better enabled as information is reconciled and standardized.

   In 2022, efforts focused on developing solutions for three business areas: Customer Service, Major Projects, and Energy Supply. For Customer Service, Enterprise Analytics is delivering a new reporting dashboard displaying key Customer Service data all in one place (gas and electric). Benefits include providing a clear and easily accessible view of factors contributing to performance, insights identifying strengths and opportunities to grow FortisBC's relationships with its customers, operational savings through more efficient customer interactions, and less effort to share metrics with parties outside of customer service. This is only the starting point, as more data sources could be included, and new ways of using the dashboard will be discovered, providing the potential to optimize continuous improvement with additional available, integrated data. For the Major Projects area, Enterprise Analytics is enabling it to provide analytical insight through dashboarding and reporting on Major Projects project budgets, schedule, and project development. Lastly, for the Energy Supply area, Enterprise Analytics is providing analytic

insights for energy loss, broadly accounting for power at different points within the FBC electricity supply chain, leveraging FBC AMI data to estimate unbilled power, improve the assignment of costs to customers, inform rate design and power purchases, and identify system losses more accurately. FBC expects to realize total O&M savings of approximately $0.125 million by the end of 2025.

Enterprise Analytics will also support streamlining existing reporting processes for financial and management reporting. Currently, the reporting processes work well with clearly defined requirements and processes but rely on manual effort. Enterprise Analytics provides an automated solution that reduces the effort required to generate reports, with expected productivity gains. This automation is achieved through the use of a data model to aggregate data sources and a reporting tool to allow for self-service. FBC plans to implement two or three automated reporting solutions in 2023.

4. **Robotics Process Automation (RPA):** This is an efficiency initiative using automation software to alleviate repetitive and simple manual tasks. With the rising volume of manual tasks performed for operational work, such as financial transactions or project closeout activities, departments within FortisBC are challenged.

   In 2022, the Company initiated the first phase of RPA implementation, working to automate several repetitive and manual processes in the Finance department and one in the Engineering department. The processes chosen were small, low-risk opportunities to introduce RPA to the organization. The first Finance process went into production in mid-2022 with others following throughout the remainder of the year. The Engineering process went into production in the first half of 2023. The automation of the Finance processes has resulted in:

   - faster and more timely processing of monthly journal entries, allowing for earlier and increased analysis and review time;
   - a shift in how time is spent, moving from data-entry-style rote work on several processes;
   - a reduction in time spent reperforming work due to human errors; and
   - an overall reduction in time spent on certain processes.

   The operational efficiency value gained by RPA is incremental but compounds as more processes are automated.

   In 2023, the Company is adding to automation within the Finance area as well as evaluating opportunities in other business areas to grow the RPA initiative. Additional process opportunities include populating Financial and Internal Audit reports and filings, application of customer bill payments, net-metering amendment of Electric bills, processing of rebate applications, onboarding of new users within IS systems, and automating manual document control processes within Engineering projects. A

governance structure will also be established to prioritize and control RPA implementations, as well as ensuring that RPA implementations align with the overall business strategy and objectives, and that the necessary resources and support are available for successful implementation and ongoing maintenance of the automated processes. FBC expects to realize total O&M savings of approximately $0.025 million by the end of 2024.

5. **Paperless Billing Customer Campaigns:** This initiative focuses on working with customers to encourage the switch to paperless billing. In addition to the convenience for customers of receiving their bill electronically and the environmental considerations of less paper and physical transport of the bills, an increased percentage of customers making the switch to paperless billing results in ongoing printing and postage cost savings. At the start of 2022, FBC had approximately 77,000 customers choosing paperless billing as their preferred bill delivery method. Following the success of several internal programs that encouraged employees to highlight this option with customers and including an external social media campaign that resulted in donations to food banks in need, FBC achieved an increase of approximately 6,500 customers choosing this option in 2022. This increase equates to approximately $0.05 million in printing and postage cost savings for FBC in 2022 as compared to 2021.[1]

6. **Other Initiatives:** FortisBC is continuously looking for efficiencies and improvements in its activities, in a larger scale as the initiatives described above, or at a smaller scale as described in the following initiatives.

Mobile enabling applications: FortisBC has different initiatives to digitize forms and provide the ability to complete these forms on mobile devices in the field or office. Digitizing these forms supports effective data capture, and improves consistency, reliability, comprehension of data collected and reduces risk of manual errors. Additionally, it reduces the administrative efforts that occur with paper forms. FortisBC expects to realize minor savings by the end of 2023, and additional savings will be realized as FortisBC continues to mobile-enable and digitize other paper forms.

Automated patching: FortisBC has started taking advantage of technologies for automated patching. Moving to automated patching has streamlined the patching process for several applications in the FortisBC environment. With automated patching, the process can be scheduled to run during a more appropriate business outage window with no user involvement required. Repetitive tasks can be automated, eliminating human error, increasing productivity, and decreasing administrative costs. FortisBC expects to realize minor O&M savings by the end of 2023 with increased patch cadence and accuracy. Additional time savings will be seen as more systems transition to automated patching.

[1] Calculation is a high-level estimate based on the incremental monthly paperless billing growth at an average savings of approximately $1.21 per bill.

Other IS Initiatives: A High Availability (HA) operating environment enables applications to continue to operate even if one of the information technology components fails, and to ensure continuous operation and uptime. HA allows IS to schedule upgrades, patches, and release tasks during business hours, ultimately improving business operations and reducing overtime costs. IS has also expanded the use of automated testing. The expanded use of automation allows for an increase in system testing and improved product quality with a decrease in proportionate need for additional testing resources. Automation is expected to continue to expand in use at FortisBC in the future.

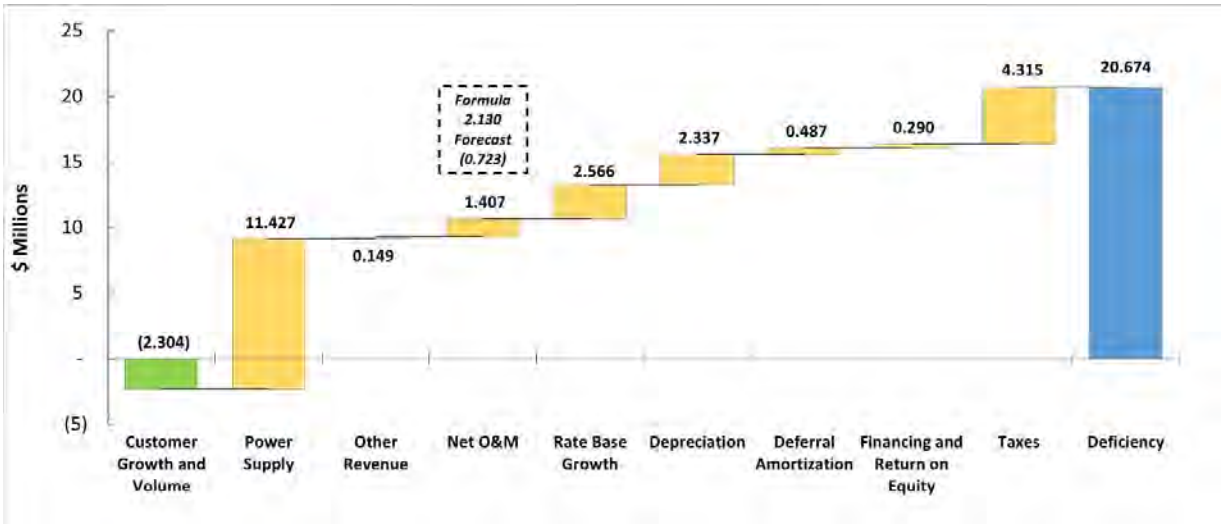
Customer Service Initiatives: Ongoing smaller initiatives include automating the tracking of collections and refund cases, improving training materials for high volume call types, and introducing emails for electric collections customers. While on a smaller scale, these initiatives contribute to improving customers' experience with FortisBC and the Company maintaining a focus on being cost effective in its use of resources.

1.5 REVENUE REQUIREMENT AND RATE CHANGES FOR 2024

The revenue requirement components set out in the Application result in an effective rate increase of 4.83 percent for 2024 compared to 2023. The effective rate increase results from a revenue deficiency of $20.674 million.

The following chart summarizes the items that contribute to the 2024 revenue deficiency. The chart shows each item that increases the deficiency in yellow and each item that decreases the deficiency in green. The 2024 deficiency of $20.674 million is then the sum of all of the previous bars and is shown at the end of the chart in blue.

Figure 1-1: 2024 Revenue Deficiency ($ millions)



Each of the categories is discussed briefly below.

1.5.1 Customer Growth and Volume Forecast (Section 3)

For 2024, FBC forecasts the net load to decrease by approximately 1 GWh when compared to 2023 Approved, with the forecast increases from the wholesale and commercial customer classes completely offset by decreases in the residential, industrial, and irrigation customer classes. Despite the slight decrease in net load of 1 GWh forecast for 2024, FBC is forecasting a small increase in revenue of $2.304 million, primarily due to the forecast increase in load from the wholesale customers as well as a forecast increase in residential and commercial customer counts (resulting in a small increase in the fixed monthly/bi-monthly customer charges). FBC's 2024 Forecast revenue at 2023 approved rates is $428.377 million.

1.5.2 Power Supply (Section 4)

FBC forecasts an increase in power supply of $11.427 million in 2024 compared to 2023 Approved. This increase is primarily due to the higher purchase rates for power from the market and contracted producers (included as part of the power purchase expense), followed by smaller increases in the BC Hydro Power Purchase Agreement (PPA), wheeling expenses, and water fees.

1.5.3 Other Revenue (Section 5)

Other Revenue is forecast to increase the 2024 revenue deficiency by $0.149 million, primarily due to reduced contract revenue and transmission access revenue.

1.5.4 Operations and Maintenance (O&M) Expense (Section 6)

FBC establishes the majority of its O&M expense by formula during the MRP term. The O&M formula incorporates a net inflation factor of 3.580 percent, which is inclusive of a productivity improvement factor (X-Factor) of 0.5 percent, and uses a forecast of the change in average customers.[2] The 2024 Formula O&M net of capitalized overhead has increased by $2.130 million[3] when compared to the 2023 Formula O&M, which is partially offset by a decrease in net O&M forecast outside of the formula by approximately $0.723 million,[4] primarily due to a decrease in pension and OPEB expense. Overall, the 2024 increase in total O&M expense net of capitalized overhead is $1.407 million (2.3 percent).

1.5.5 Rate Base Growth (Section 7)

The 2024 rate base is forecast to increase by approximately $39.492 million when compared to the 2023 Approved rate base, resulting in an increase to the 2024 Forecast earned return and the 2024 revenue deficiency of approximately $2.566 million. The increase in rate base is primarily due to the mid-year impact of FBC's 2024 regular capital additions to plant, followed by, to a lesser extent, the full-year impact of FBC's major capital project additions, including the Kelowna

[2] Modified by 75 percent.
[3] Increase in gross formula O&M of $2.506 million (3.6 percent) compared to 2023 Approved.
[4] Decrease in gross forecast O&M of $0.850 million (-36.2 percent) compared to 2023 Approved.

Bulk Transformer Additions (KBTA) project and the Corra Linn Dam Spillway Gates Replacement project.

1.5.6 Depreciation (Section 7)

Depreciation expense in 2024 is forecast to increase the 2024 revenue deficiency by $2.579 million compared to 2023 Approved. This increase is due to the forecast increase in rate base discussed above. The increase in depreciation expense is partially offset by approximately $0.242 million of CIAC from net additions, resulting in a net increase of $2.337 million in depreciation expense.

1.5.7 Amortization of Deferral Accounts (Section 7 and Section 12)

Amortization of deferral accounts in 2024 is forecast to increase by $0.487 million, primarily due to a reduction in the credit amortization related to the 2020-2024 Flow-through non-rate base deferral account. This increase in amortization expense due to the reduced credit amortization from the Flow-through deferral account is partially offset by an increase in credit amortization from the MRP Earnings Sharing deferral account as well as the amortization of credit balances in the Princeton Office Disposition deferral account, the proposed BC Cost of Living Credit deferral account, and the proposed PST Rebate on Select Machinery and Equipment deferral account.

1.5.8 Financing and Return on Equity (Section 8)

Financing and Return on Equity (ROE) increased the 2024 deficiency by $0.290 million through changes in financing rates, the ratio of long-term debt versus short-term debt, and changes in rate base.

For 2024, FBC is forecasting a short-term debt rate of 5.21 percent, which is an increase from the short-term debt rate embedded in the 2023 Approved revenue requirement of 4.24 percent. Overall, FBC's revenue deficiency is increased by $0.346 million from financing rate changes, which is offset by $0.056 million from the ratio change between long-term and short-term debt.

In calculating its 2024 revenue deficiency, FBC has utilized its currently approved capital structure and return on equity (ROE) of 40 percent and 9.15 percent, respectively, as approved by Orders G-129-16 and G-47-14. As explained in Section 8.1, FBC's ROE is set at a premium of 40 basis points over the benchmark ROE, which is the ROE approved for FEI. FBC is currently awaiting a decision on Stage 1 of the BCUC-initiated Generic Cost of Capital (GCOC) proceeding which is expected to be issued in the upcoming months. FBC will provide an update to its rate calculations as part of an Evidentiary Update subsequent to the GCOC decision being issued.

1.5.9 Taxes (Section 9)

FBC's 2024 property taxes are forecast to increase by 1.7 percent or $0.313 million from 2023 Approved. The increase is primarily due to changes in tax rates and increases in assessed values.

There has been no change in the income tax rate of 27 percent from 2023. Taxes are forecast to increase in 2024 by $4.002 million. The largest driver of the increase in 2024 is the lower income tax deductible through capital cost allowance (CCA), which led to an increase in income tax expense by approximately $2.849 million. The lower CCA is partly due to reduced undepreciated capital cost (UCC) additions in higher rate CCA classes in the 2024 Forecast compared to 2023 Approved, and partly due to the phase-out of Canada's Accelerated Investment Incentive starting from 2024 (i.e., enhanced 50 percent first-year allowance to be phased out in 2024). Income tax is also higher as a result of higher 2024 Forecast earned return and depreciation expense, which is partially offset by lower amortization of deferred charges.

1.6 SERVICE QUALITY INDICATORS (SECTION 13)

FBC reports on its 2022 and June 2023 year-to-date SQI results in Section 13. In 2022, for the eight SQIs with benchmarks, six met or were better than the benchmark, with the First Contact Resolution SQI better than the threshold and the Telephone Service Factor (Non-Emergency) SQI lower than the threshold. For the four SQIs that are informational only, the Average Speed of Answer results were higher due to the same challenges impacting the Telephone Service Factor (Non-Emergency), while performance in 2022 for the other three informational metrics generally remained at a level consistent with prior years. In 2023 to date, performance for the metrics with benchmarks is trending towards meeting the benchmark or the threshold.

2. FORMULA DRIVERS

2.1 INTRODUCTION AND OVERVIEW

This section provides the calculation of the Inflation Factor (or I-Factor) and Growth Factor used for calculating the 2024 O&M amounts according to the MRP formula.

In the MRP Decision and Order G-166-20, the BCUC approved an I-Factor using the actual CPI-BC and BC-AWE indices from the previous year and a labour weighting based on the most recent completed year of actuals.[5]

The MRP Decision approved the use of a forecast of growth[6] to determine formula O&M and determined that a growth factor multiplier of 75 percent for formula O&M was appropriate.

The Inflation Factor and Growth Factor calculations utilize the above-described inputs and determinations. For 2024, FBC has used July 2021 through June 2023 inflation data for the 2024 revenue requirement calculations, using the Statistics Canada tables included in Appendix A1 of the Application.

Section 2.2 below explains how FBC determined the 2024 Inflation Factor based on prior years' BC-CPI and BC-AWE, and Section 2.3 below explains how FBC determined the average customer count. Both the inflation factor and the average customer count are used to calculate the formula O&M discussed in Section 6.

2.2 INFLATION FACTOR CALCULATION SUMMARY

In the MRP Decision, the BCUC approved an I-Factor using the actual CPI-BC and BC-AWE indices from the previous year and the actual labour weighting based on the most recent completed year of actuals. FBC uses inflation data from July through June and Statistics Canada Table 18-10-0004-01 for CPI-BC and Table 14-10-0223-01 to determine AWE-BC. The supporting Statistics Canada tables are provided in Appendix A1. The latest available month of April 2023 for AWE-BC has been used as a placeholder, as results to June 2023 have not been released by Statistics Canada. Once results for these periods are available, this placeholder will be replaced with actuals and included in an Evidentiary Update or Compliance Filing.

As shown in Table 2-1 below, the I-Factor has been calculated utilizing actual CPI-BC and AWE-BC data. Applying the actual 2022 labour weighting of 57 percent, the calculation of the 2024 I-Factor is (6.031 percent x 43 percent) + (2.609 percent x 57 percent) = 4.080 percent.

[5] FBC's most recent year of completed actuals is 2022 so that ratio has been used for the 2024 I-Factor calculation.
[6] Forecast of average customers for Formula O&M, including a true-up to actual customers in the following years.

Table 2-1: I-Factor Calculation

Line No.	Date	*Table: 18-10-0004-01* BC CPI index	*Table: 14-10-0223-01* BC AWE $	12 Mth Average CPI index	12 Mth Average AWE $	CPI %	AWE %	Last Completed Year Non Labour %	Last Completed Year Labour %	I-Factor %	MRP Year
1	Jul-2021	136.7	1,143.76								
2	Aug-2021	137.0	1,143.96								
3	Sep-2021	137.2	1,142.37								
4	Oct-2021	137.9	1,140.94								
5	Nov-2021	138.1	1,129.51								
6	Dec-2021	138.0	1,132.93								
7	Jan-2022	139.4	1,155.32								
8	Feb-2022	140.4	1,153.57								
9	Mar-2022	143.0	1,161.00								
10	Apr-2022	144.2	1,164.51								
11	May-2022	146.1	1,159.89								
12	Jun-2022	146.5	1,167.14	140.4	1,149.58						
13	Jul-2022	147.6	1,162.26								
14	Aug-2022	147.0	1,171.52								
15	Sep-2022	147.8	1,171.94								
16	Oct-2022	148.6	1,174.29								
17	Nov-2022	148.1	1,176.97								
18	Dec-2022	147.1	1,153.31								
19	Jan-2023	148.1	1,180.04								
20	Feb-2023	149.1	1,175.83								
21	Mar-2023	149.7	1,191.20								
22	Apr-2023	150.4	1,199.14								
23	May-2023	151.0	1,199.14								
24	Jun-2023	151.6	1,199.14	148.8	1,179.57	6.031%	2.609%	43%	57%	4.080%	2024

2.3 GROWTH FACTOR CALCULATION SUMMARY

As noted above, the BCUC approved the use of a forecast of average customers with a 75 percent modifier to determine formula O&M.

The calculation of average customers used to determine 2024 Formula O&M is summarized in the table below. The growth factor is applied to the unit cost O&M (UCOM), which was calculated based on 2019 average customers of 139,916 (shown on line 21 under year 2020 or line 28 in Table 2-2 below). Starting with this 2019 average customer count, the calculation adds 75 percent of the cumulative average of actual/forecast customer growth during the MRP term from 2020 to 2024 (shown on line 26 in Table 2-2 below) to determine the average customers for rate setting (shown on line 29 of Table 2-2 below).

Table 2-2: Calculation of 2024 Average Customer (AC) Growth Factor

Line No.	Date	Actual 2020	Actual 2021	Actual 2022	Projected 2023	Forecast 2024	Total for 2024 Rate Setting	Reference
1	Prior Year Ending Customer Count	141,027	143,714	145,830	148,435	150,761		Appendix A2 - Section 3.1 Customers
2								
3	Additions:							
4	January	292	257	226	162	192		
5	February	174	89	194	189	194		
6	March	8	123	122	192	191		
7	April	110	113	178	169	193		
8	May	173	319	(25)	277	185		
9	June	172	116	353	121	192		
10	July	522	308	352	245	193		
11	August	129	187	204	193	191		
12	September	83	136	155	195	193		
13	October	545	132	261	197	195		
14	November	234	217	319	190	188		
15	December	245	119	266	197	195		
16	Total Additions	2,687	2,116	2,605	2,326	2,302		Appendix A2 - Section 3.2 Customer Additions
17	12-month Weighted Average Additions	1,294	1,163	1,282	1,242	1,245		
18								
19	Current Year Ending Customer Count	143,714	145,830	148,435	150,761	153,063		Line 1 + Line 16; Appendix A2 - Section 3.1 Customers
20								
21	Actual/Projected Prior Year Average Customers	139,916	142,321	144,877	147,112	149,677		2020: G-42-21; Sch 3, Line 13; 2021-2024: Prior Year, Line 22
22	Average Customers for the Year	142,321	144,877	147,112	149,677	152,006		Line 1 + Line 17
23	Change in Average Customers	2,405	2,556	2,235	2,565	2,329	**12,090**	Sum of Annual Change in Average Customers on Line 23
24								
25	Growth Factor Multiplier						**75%**	G-166-20
26	Change in Average Customers for Rate Setting Purposes						**9,068**	Line 25 x Line 23
27								
28	Average Customers Used to Determine the Starting UCOM						**139,916**	Line 21, Yr 2020
29	**Average Customer Forecast for Rate Setting**						**148,984**	Line 28 + Line 26
30								
31	2022 Approved Average Customers for Rate Setting			145,378				2022: G-374-21; Sch 3, Line 22
32	2022 Actual Average Customers for Rate Setting			145,313				Line 21 (2020) + Sum of Line 23 (2020, 2021, 2022) x 0.75
33	**2022 True Up**			**(65)**				Line 32 - Line 31

2.4 INFLATION AND GROWTH CALCULATION SUMMARY

A summary of the factors used to determine formula O&M for 2024 is provided in Table 2-3, including the I-Factor calculated in Section 2.2, the approved X-Factor of 0.5 percent, and the forecast of average customers incorporating the growth factor multiplier determined in Section 2.3.

Table 2-3: Summary of Formula Drivers

Line No.	Description	2024	Reference
1	CPI	6.031%	Table 2-1, Line 24
2	AWE	2.609%	Table 2-1, Line 24
3			
4	Non Labour	43%	Table 2-1, Line 24
5	Labour	57%	Table 2-1, Line 24
6			
7	CPI/AWE Inflation	4.080%	(Line 1 x Line 4) + (Line 2 x Line 5)
8			
9	Productivity Factor	-0.500%	Order G-166-20
10			
11	Net Inflation Factor	3.580%	Line 7 + Line 9
12			
13	Average Customer Forecast for Formula O&M purposes	148,984	Table 2-2, Line 29

In summary, the Net Inflation Factor for 2024 is 3.580 percent and formula O&M for 2024 is determined using average customers of 148,984.

3. LOAD FORECAST AND REVENUE AT EXISTING RATES

3.1 INTRODUCTION AND OVERVIEW

This section describes FBC's forecast of gross system load. The gross system load is a combination of residential, commercial, wholesale, industrial, lighting and irrigation loads, system losses and company use. The forecast of gross system load includes the impacts of forecast load savings which include Demand Side Management (DSM) savings. These savings are further explained in Section 3.3 – Demand Side Management Savings.

FBC is forecasting a decrease in consumption in the 2024 Forecast (2024F) compared to the 2023 Approved. The 2024F gross load is forecast to be approximately 3,773 GWh, which is 2 GWh lower than the 2023 Approved gross load. The decrease is primarily due to a reduction in loads from the residential, industrial, and irrigation classes, which almost completely offsets the increase in loads from the wholesale and commercial customers. Despite the decrease in the 2024 Forecast gross load, FBC is forecasting the 2024 revenue to be $428.377 million, which is an increase of $2.304 million when calculated based on the 2023 Approved rates for each customer class. The increase in revenue for 2024 is primarily due to the forecast increase in load from the wholesale customers, as well as an increase in recoveries from the fixed monthly/bimonthly customer charges resulting from the forecast increase in customer counts in the residential and commercial classes.

FBC has provided further information supporting its load forecast in Appendix A of the Application.

3.2 OVERVIEW OF FORECAST METHODS

Consistent with the forecasting method followed by FBC in previous years, the load forecast relies on the following components:

- the residential and commercial customer count forecast;
- the residential use per customer (UPC) forecast;
- the commercial, lighting and irrigation load forecast; and
- the industrial and wholesale survey forecast.

The load forecast for residential customers is based on forecasts for the number of customers and UPC rates. Specifically, the UPC forecast is multiplied by the corresponding forecast of the number of annual average customers to derive the residential load forecast. The commercial load forecast is based on a regression against the Conference Board of Canada (CBOC) Gross Domestic Product (GDP) forecast, the lighting forecast uses the prior year's actual load, and the irrigation forecast uses a five-year historical average. Finally, wholesale and industrial forecasts are primarily based on customer-specific survey results.

More detail on FBC's forecasting methods can be found in Appendix A of this filing.

The following sections set out the results of the load forecast. In the figures provided in the load forecast sections, the following three time periods are shown:

- Actual Years: Actual years are those for which actual data exists for the full calendar year. For this Annual Review the latest calendar year for which full actual data exists is the 2022 calendar year.

- Seed Year: The Seed Year is the year prior to the first forecast year. The Seed Year is forecast based on the latest years of actual data available,[7] and will be different than the original forecast for that year in the previous filing. For example, for this Application the Seed Year is 2023 (2023S) and the Seed Year forecast is based on the latest actual years, including 2022. As such, the 2023 Seed Year forecast in this Application will differ from the 2023 Forecast presented in the Annual Review for 2023 Rates, for which 2022 actual data was not available.

- Forecast Year: This is the year or years for which the forecast is being developed. This can be one year (in the case of the Annual Review) or a range of two or more years depending on the filing. In this Application, the forecast year is 2024 (2024F).

- Also included in the figures in this section is the prior year's forecast (shown as the green Approved lines in the figures below), as presented in the Annual Review for 2023 Rates.

FBC acquired the utility assets and customers of the City of Kelowna's electric utility effective March 31, 2013, resulting in an increase in direct customers and changes in the composition of customers and sales load by class, which are reflected in the data and figures in this section.

3.3 DEMAND SIDE MANAGEMENT SAVINGS

FBC forecasts the DSM savings that are incremental to the DSM savings that are already embedded in historical loads up to and including 2022.

The DSM savings forecast is deducted from the before-savings forecast for all customer classes. All forecast values in the sections below are shown after being reduced by DSM savings unless explicitly stated otherwise.

The forecast incremental DSM savings for 2024 are summarized in Table 3-1 below, and are the forecast savings incremental to the savings embedded in the historical loads. Historical DSM savings can be found in Appendix A2.

[7] FBC's load forecast is developed using only complete years of historical data. FBC requires the complete year of load data in order to validate it, including the review of and potential adjustments to unbilled energy. For this reason, partial year data is not used in forecasting.

Table 3-1: Forecast Incremental 2024 DSM Savings (GWh)

Line No.	Description	DSM 2024
1	Residential	(9.1)
2	Commercial	(22.3)
3	Wholesale	(7.6)
4	Industrial	(13.5)
5	Lighting	(0.2)
6	Irrigation	(0.2)
7	Net	(52.9)
8	Losses	(4.3)
9	Gross Load	(57.2)

3.4 LOAD FORECAST

FBC's total load consists of the weather normalized residential and wholesale load and the actual commercial,[8] industrial, lighting and irrigation load. In aggregate, the absolute load forecast variance in 2022 was 4.7 percent, which was primarily due to higher industrial loads and more residential customers coming onto the system than forecast. As shown in Figure 3-1 below, the total load, net of losses, is forecast to be 3,473.9 GWh in 2024F, which is 1.8 GWh less than 2023S and 1.4 GWh less than 2023 Approved.

[8] Commercial loads are tested for weather sensitivity each year. For 2024, there is a low correlation with weather and as a result, the actual historic commercial loads are used in the preparation of Figures 3-1 and 3-5. Please refer to Section 1.1 of Appendix A-3 for further detail.

Figure 3-1: Total Net Load (GWh)

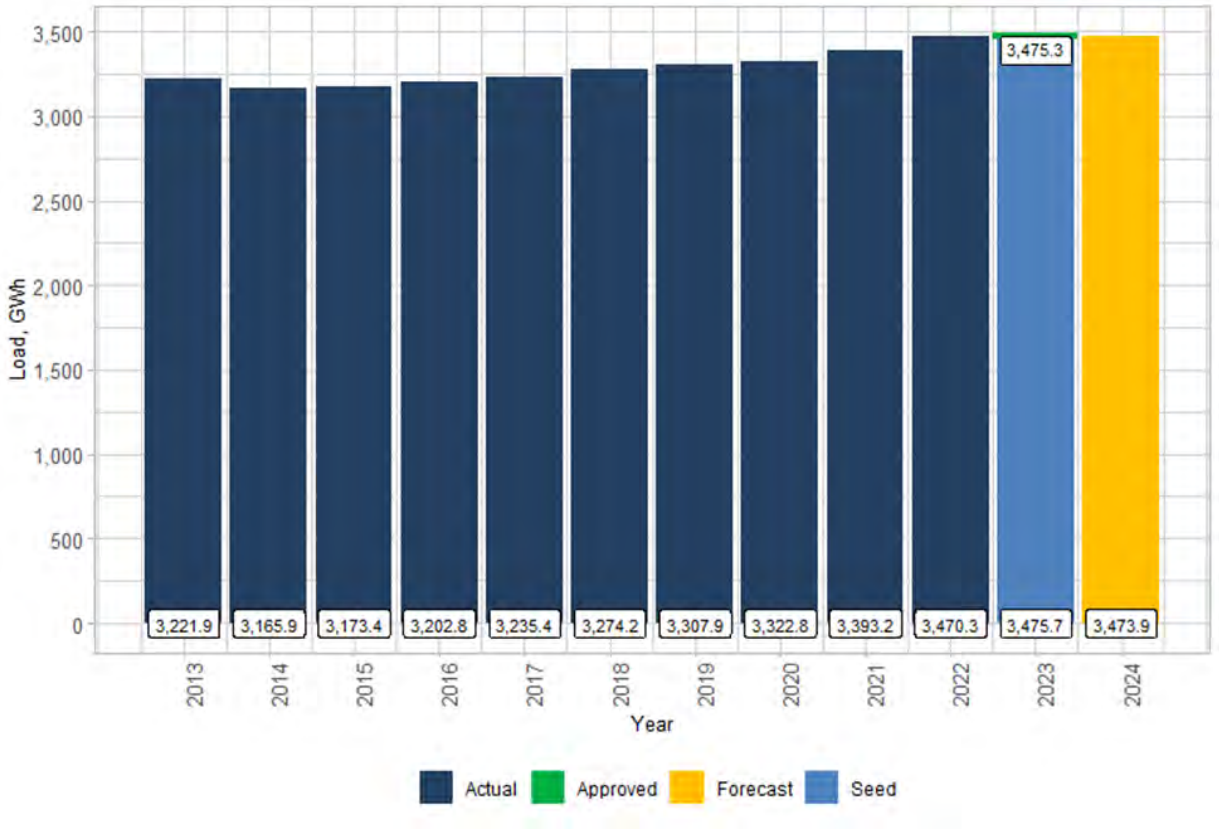


Table 3-2 below shows the normalized after-savings gross load by customer class as well as the system peak. For 2024F, the residential customer class is forecast to account for 34 percent of the normalized after-savings gross load.

Table 3-2: After-Savings Gross Load and System Peak[9]

Line No.	Description	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023S	2024F
	Energy (GWh)												
1	Residential	1,352.9	1,296.5	1,298.1	1,295.6	1,320.5	1,312.6	1,266.1	1,346.8	1,330.3	1,320.4	1,307.6	1,298.9
2	Commercial	788.2	865.7	853.2	901.4	920.4	922.0	933.9	917.2	971.4	969.1	967.5	974.2
3	Wholesale	675.2	567.1	580.5	574.4	574.1	584.7	566.0	569.5	565.8	575.5	590.7	589.8
4	Industrial	352.3	380.9	379.7	373.4	362.6	402.7	494.9	441.2	472.3	558.5	562.1	563.5
5	Lighting	13.5	15.6	15.9	15.9	15.9	13.2	11.0	10.8	9.7	9.3	9.2	9.1
6	Irrigation	39.7	40.0	46.0	42.1	41.9	39.0	36.0	37.3	43.6	37.6	38.6	38.5
7	Net Load	3,221.9	3,165.9	3,173.4	3,202.8	3,235.4	3,274.2	3,307.9	3,322.8	3,393.2	3,470.3	3,475.7	3,473.9
8	Losses & Company Use	278.1	270.1	272.4	273.8	282.3	285.1	286.9	287.9	299.7	314.6	298.9	298.7
9	Gross Load	3,500.0	3,436.0	3,445.8	3,476.6	3,517.7	3,559.4	3,594.8	3,610.8	3,692.8	3,784.8	3,774.5	3,772.7
10													
11	System Peak (MW)												
12	Winter Peak	698.1	692.6	685.0	754.7	713.6	682.2	732.4	730.8	684.8	734.3	783.4	785.0
13	Summer Peak	600.4	619.5	611.0	593.0	604.8	630.9	639.4	666.2	652.9	689.1	696.2	697.3

[9] The system peaks shown on Lines 12 and 13 are weather-normalized winter and summer peaks. Refer to Section 3.4.8 for further details.

The residential, commercial, wholesale, industrial, lighting, irrigation, loss load and the winter and summer peak demand forecasts are provided separately in the following subsections.

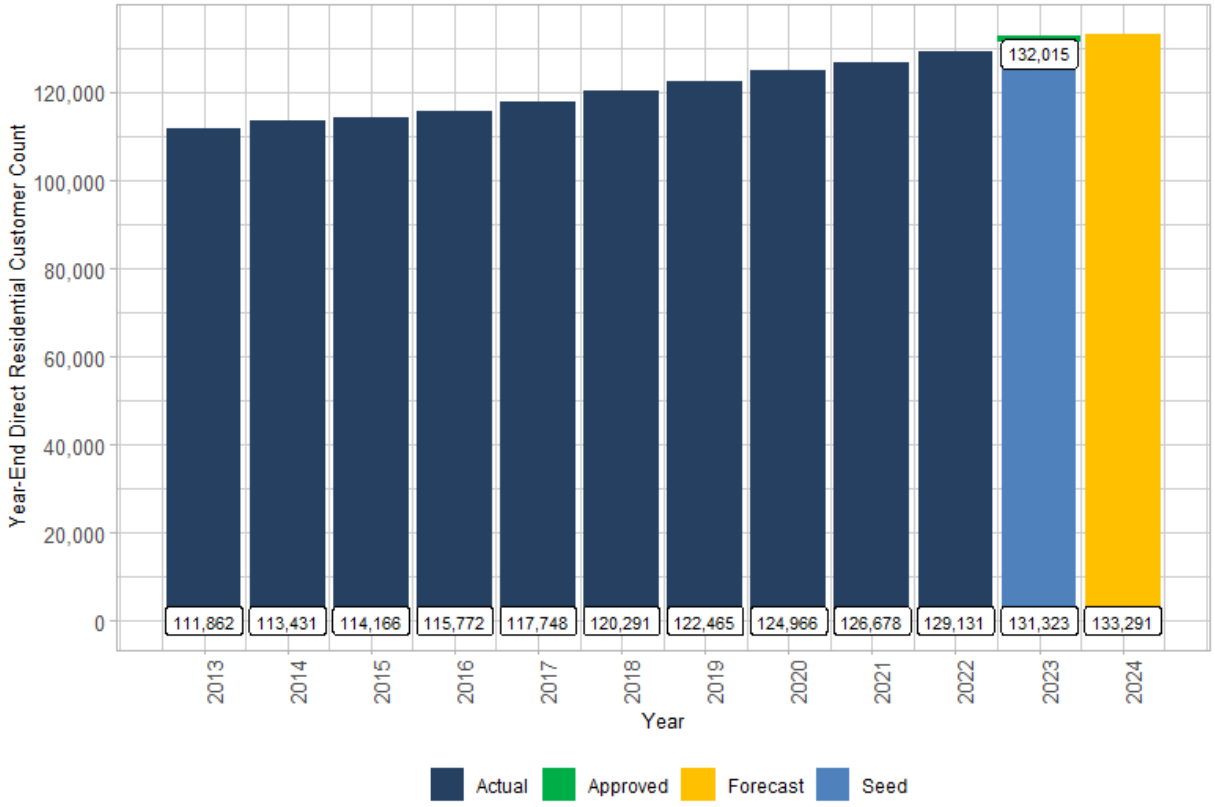
3.4.1 Residential

3.4.1.1 Residential Customers

Forecast residential customer counts are determined by a regression of the year-end customer accounts against population in the FBC direct service area. The population forecast for the FBC service area is provided by a BC Statistics report produced for FBC.

Figure 3-2 shows the year-end direct residential customer count for FBC.

Figure 3-2: Year-End Direct Residential Customer Count



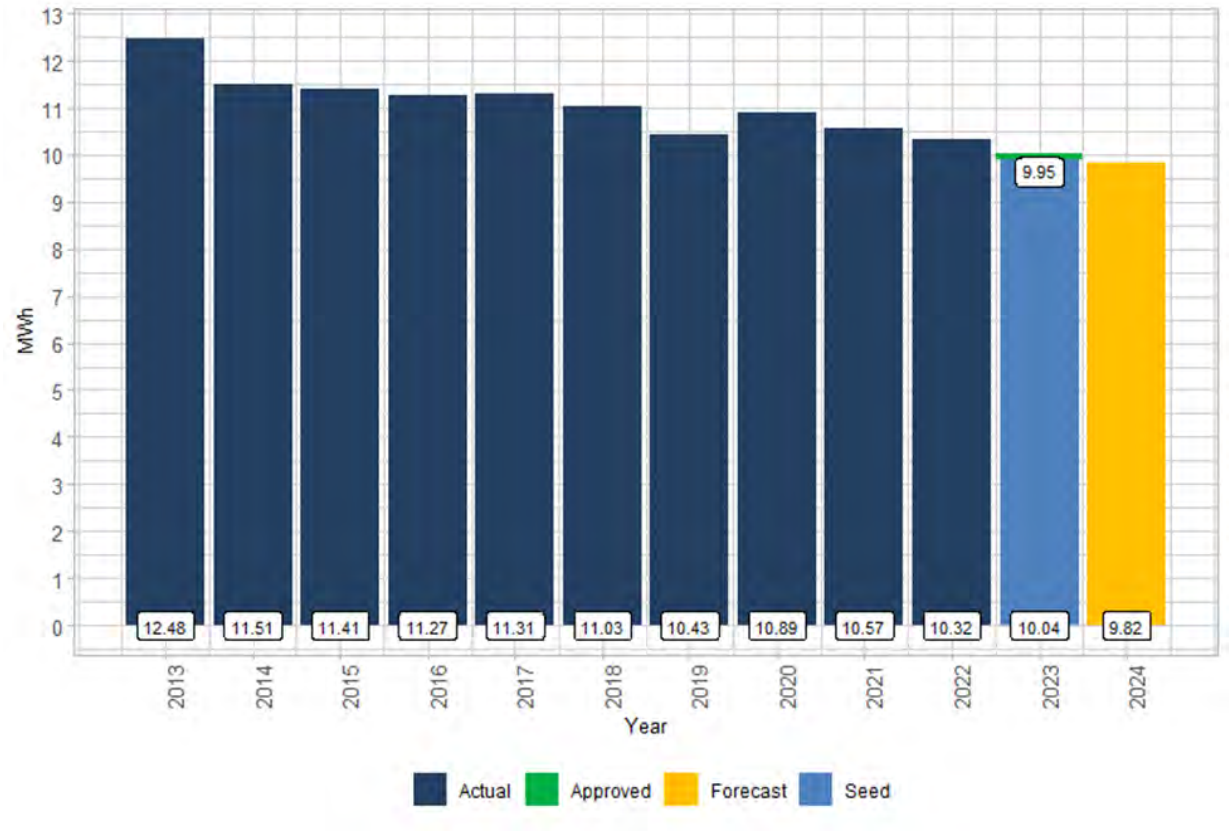
3.4.1.2 Residential UPC

Normalized historical UPCs are obtained by dividing the weather-normalized residential load by the average customer count in each year. The before-savings UPC is forecast by applying a 10-year trend to the normalized historical UPCs. The before-savings UPC forecast is then multiplied by the forecast average customer count to derive the before-savings load forecast. DSM savings, which are incremental to the savings embedded in the historical data to 2022, are then deducted

from the before-savings load forecast to determine the after-savings load forecast. The after-savings UPC forecast is then calculated by dividing the after-savings load forecast by the average customer count.

As shown in Figure 3-3 below, the residential after-savings UPC is forecast to decrease by 0.22 MWh in 2024F from 2023S and decrease by 0.13 MWh from 2023 Approved.

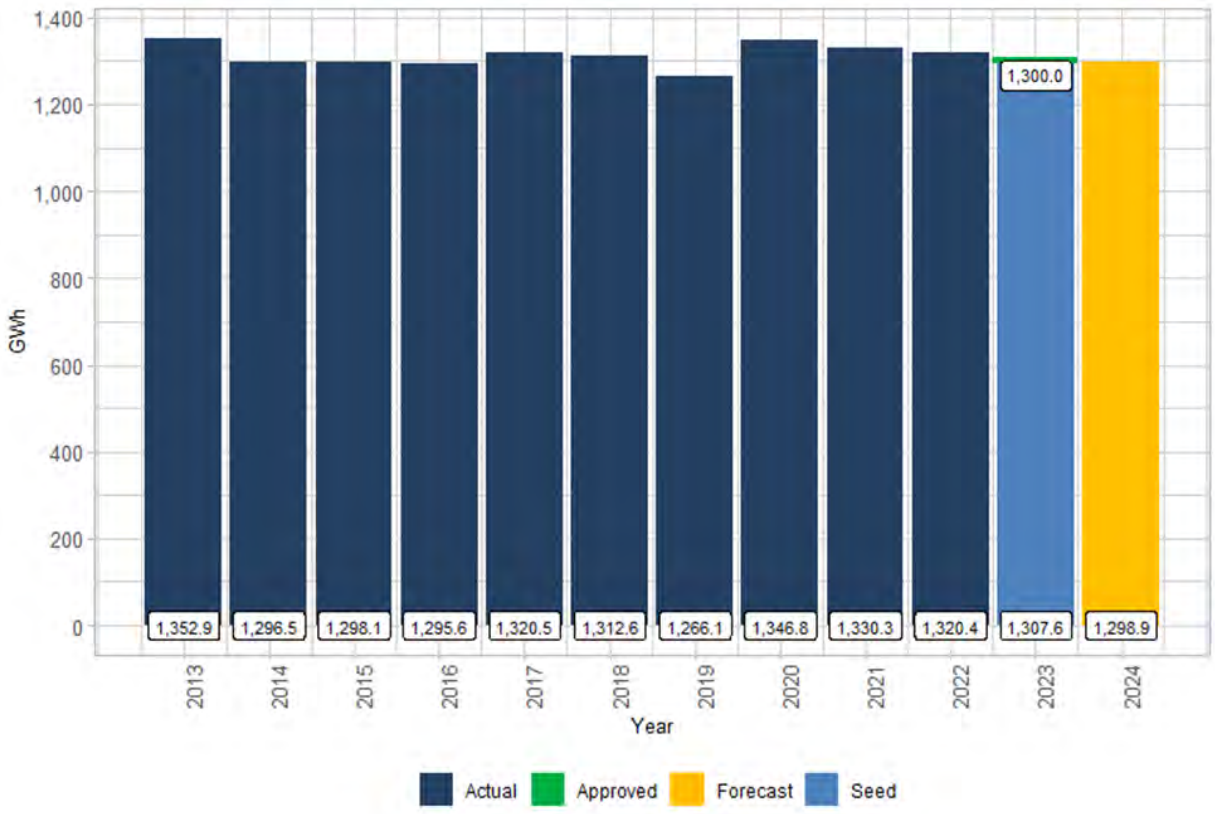
Figure 3-3: Normalized After-Savings Residential UPC (MWh)



3.4.1.3 Residential Load

Consistent with past practice, the total before-savings load for the residential class is the product of the average annual residential customer count multiplied by the residential UPC. The after-savings load is produced by taking the before-savings load and then subtracting DSM savings. As shown in Figure 3-4 below, residential after-DSM savings load is forecast to decrease by 8.7 GWh in 2024F from 2023S and decrease by 1.1 GWh from 2023 Approved levels.

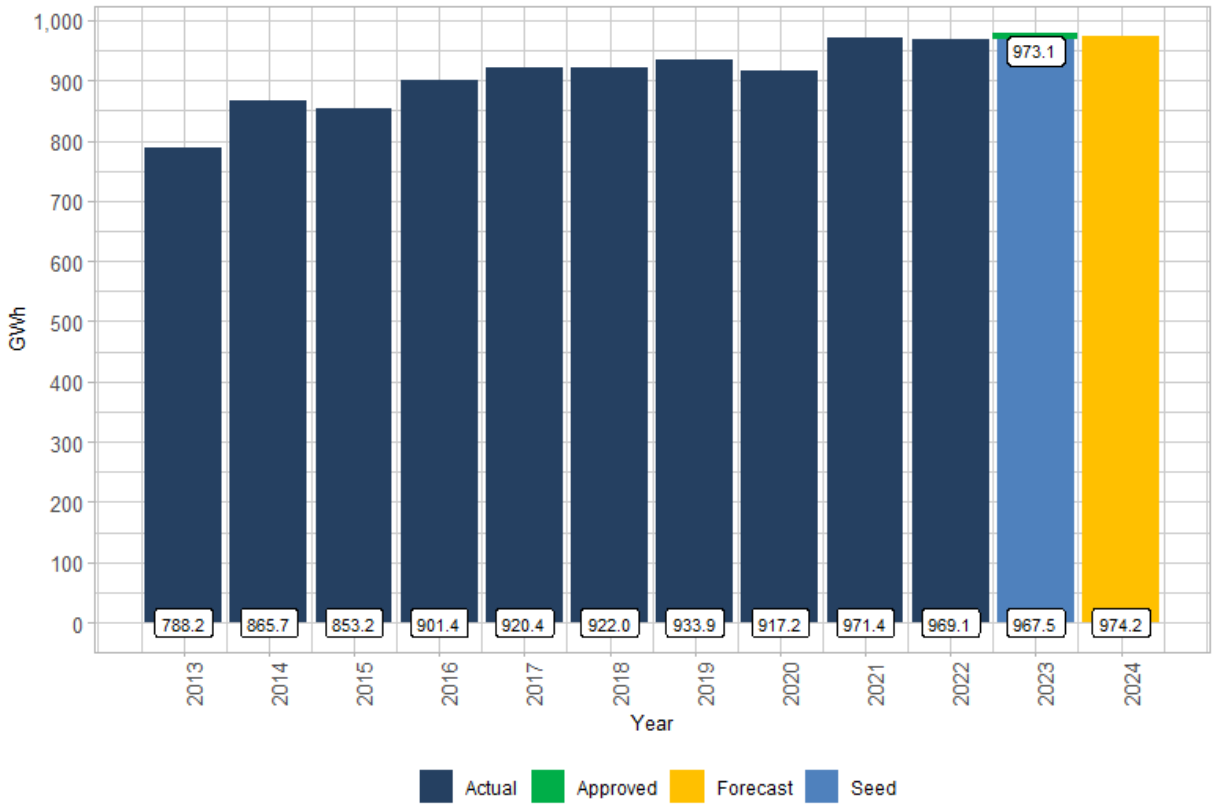
Figure 3-4: Normalized After-Savings Residential Load (GWh)



3.4.2 Commercial

The commercial class load and customer forecasts are based on regressions against the provincial GDP forecast obtained from the CBOC. The load for Electric Vehicle Direct Current Fast Chargers (EV DCFC) serviced by FBC are then added to 2023S and 2024F and account for a less than 1 GWh increase in both 2023S and 2024F. As shown in Figure 3-5 below, commercial after-savings load is forecast to increase by 6.7 GWh in 2024F from 2023S and increase by 1.1 GWh in 2024F from 2023 Approved.

Figure 3-5: After-Savings Commercial Load (GWh)



3.4.3 Wholesale

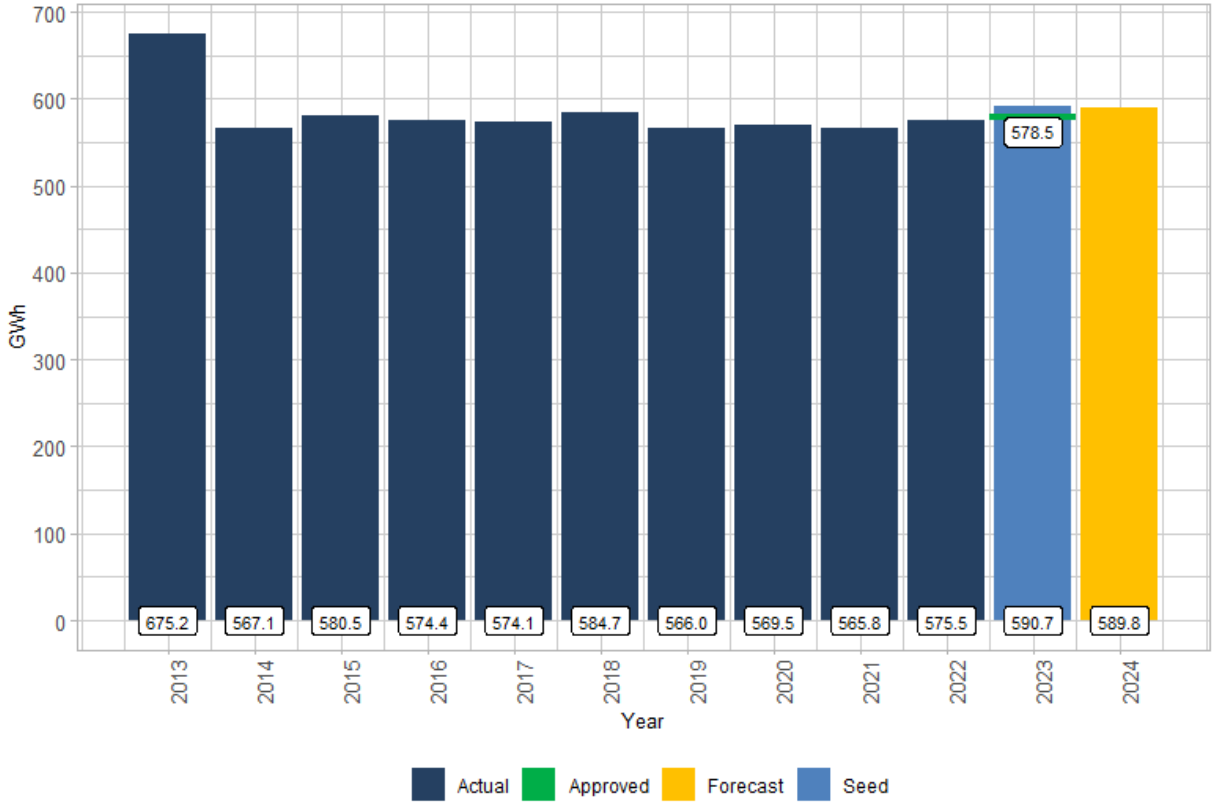
FBC sells wholesale power to municipalities for service to certain customers within its service territory that own and operate their own electrical distribution systems, and to BC Hydro. The wholesale customers' load composition is a combination of residential, commercial, industrial and lighting.

Consistent with past practice, the wholesale class is forecast using survey information from each of the individual wholesale customers, as the individual wholesale customers are best able to forecast their future load growth. For 2024, all wholesale customers responded with their load forecasts.

Consistent with the approach taken when preparing last year's wholesale load forecast (i.e., the load forecast presented in the Annual Review for 2023 Rates), FBC once again invited each wholesale customer to a workshop. In April 2023, workshops were completed with both the City of Penticton and the City of Nelson. The remainder of the wholesale customers declined the invitation. FBC continues to find these information sharing sessions valuable and plans to continue them in the future.

As shown in Figure 3-6 below, after-savings wholesale load is forecast to decrease by 0.9 GWh in 2024F from 2023S and increase by 11.3 GWh in 2024F from 2023 Approved.

Figure 3-6: Normalized After-Savings Wholesale Load (GWh)



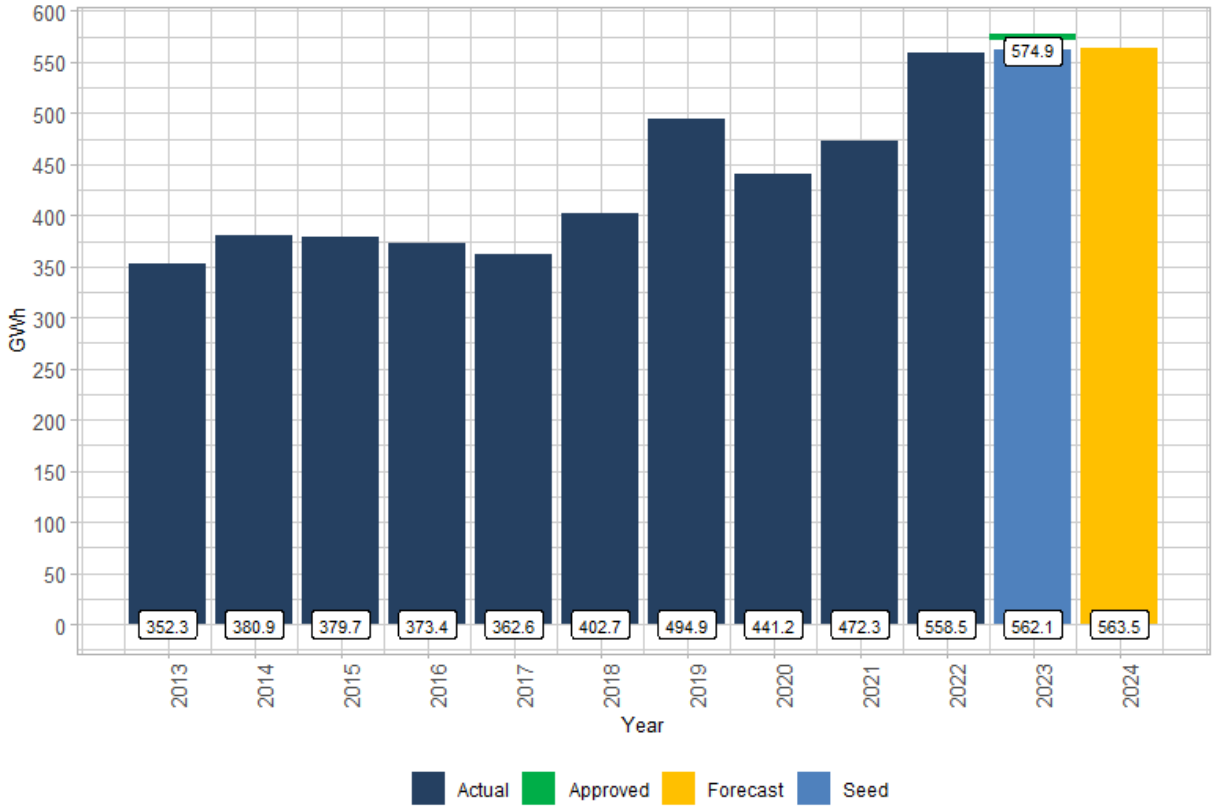
3.4.4 Industrial

Consistent with past practice, the industrial forecast is determined through a combination of customer load surveys and, when not available, escalation of the most recent annual loads by the corresponding provincial GDP growth rates for individual industries.

FBC sends all existing industrial customers a load survey that requests the customer's anticipated use for the next five years. A survey is used because individual industrial customers have the best understanding of what their future load will be. This year FBC received a response from 76 percent (32 of 42) of the surveys sent out. The responding customers represent approximately 91 percent of the total industrial load.

As shown in Figure 3-7 below, after-savings industrial load is forecast to increase by 1.4 GWh in 2024F when compared to 2023S and decrease by 11.4 GWh in 2024F compared to 2023 Approved.

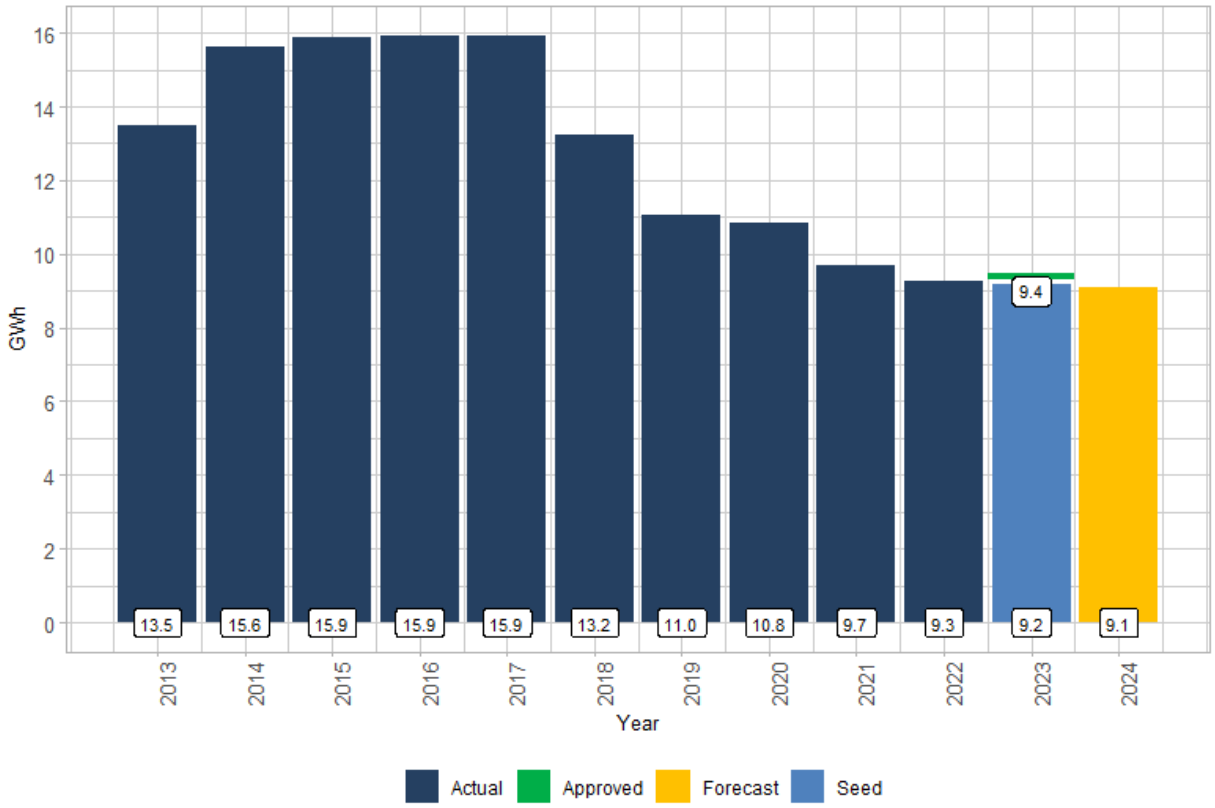
Figure 3-7: After-Savings Industrial Load (GWh)



3.4.5 Lighting

Due to the implementation of LED streetlights, the lighting load has been declining since 2017. FBC used the 2022 actuals as the forecast for this load and then reduced it by DSM savings. As shown in Figure 3-8 below, after-savings lighting load is forecast to decrease by 0.1 GWh in 2024F from 2023S and decrease by 0.3 GWh when compared to 2023 Approved.

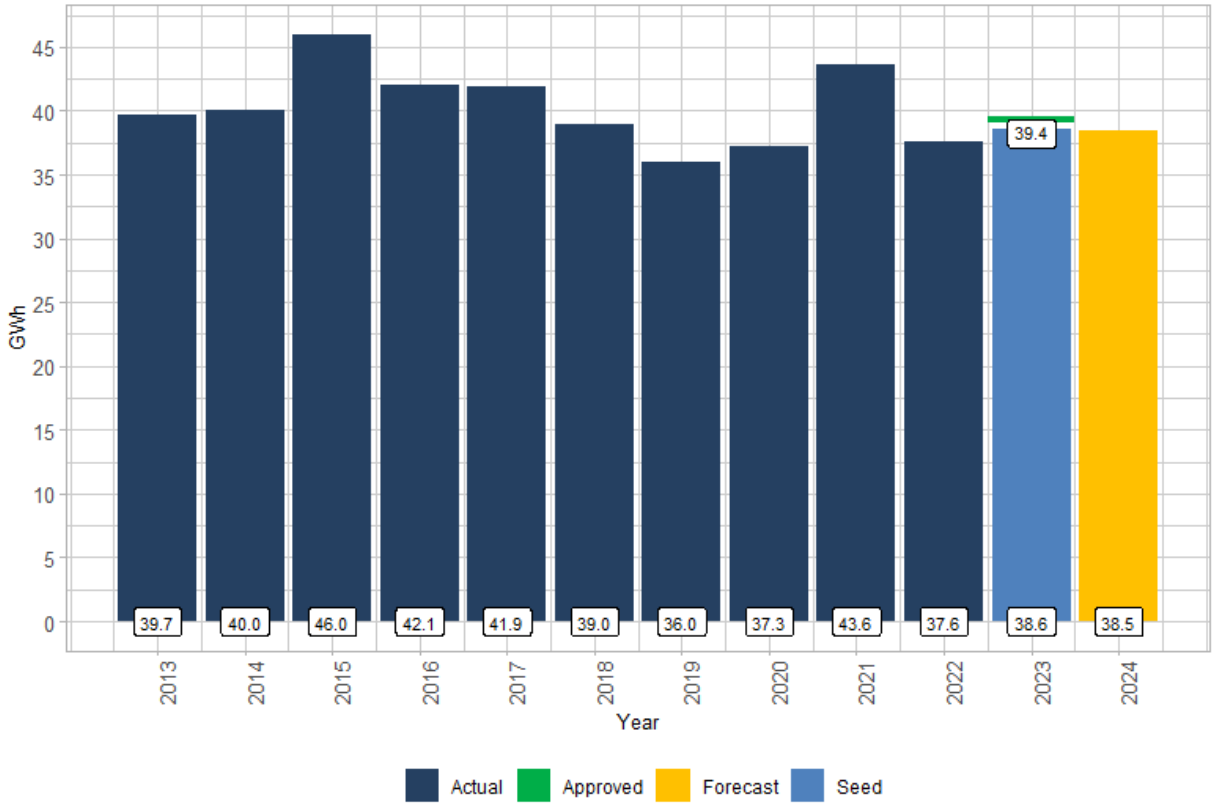
Figure 3-8: After-Savings Lighting Load (GWh)



3.4.6 Irrigation

Due to the variability in the load in the recent historical data, FBC used a five-year average as the forecast for the irrigation load. As shown in Figure 3-9 below, after-savings irrigation load is forecast to decrease by 0.1 GWh from 2023S to 2024F and decrease by 0.9 GWh in 2024F when compared to 2023 Approved.

Figure 3-9: After-Savings Irrigation Load (GWh)



3.4.7 Losses and Company Use

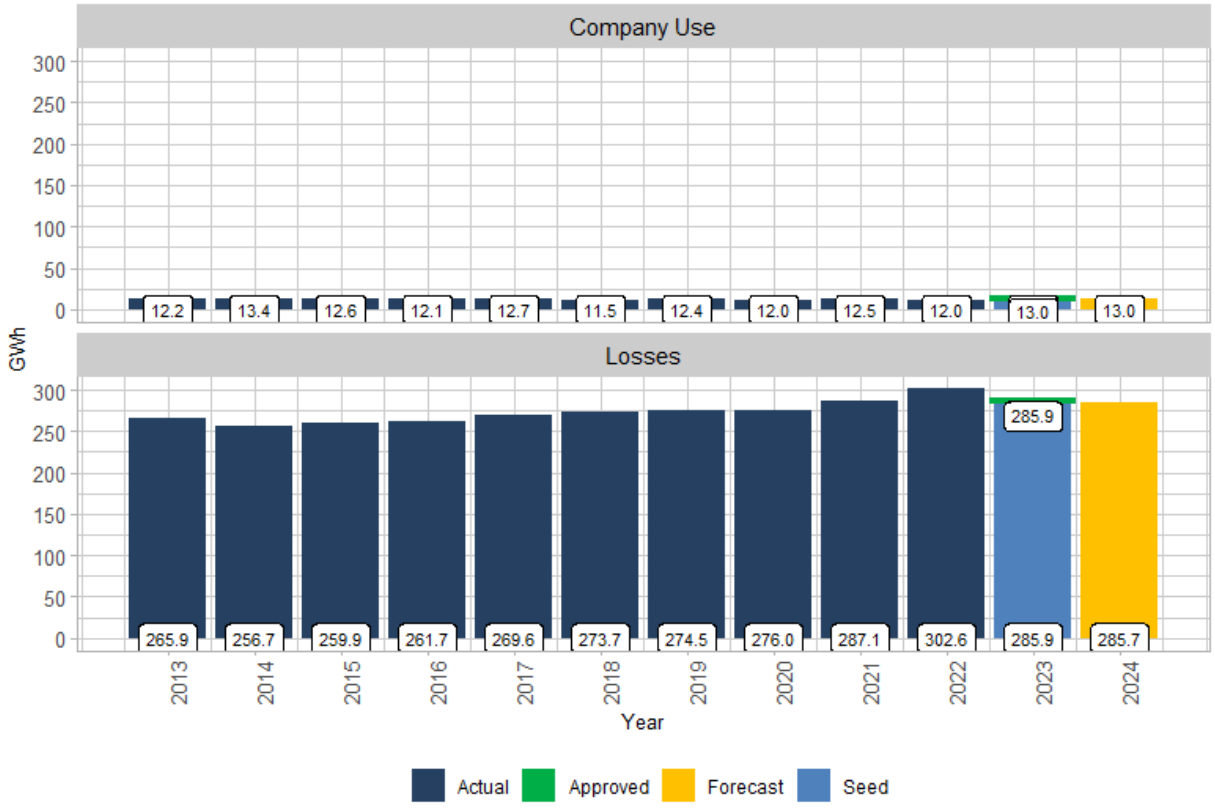
FBC conducted a Losses Study in 2019[10] and, consistent with that study, has assumed a loss rate of 7.6 percent of gross load (excluding company use). System losses consist of:

- Losses in the transmission and distribution system;
- Losses due to wheeling through the BC Hydro system; and
- Unaccounted-for load (meter inaccuracies and theft).

As shown in Figure 3-10 below, after-savings load losses are forecast to remain constant in 2024F because the gross load is forecast to be relatively stable when compared to 2023S. When compared to 2023 Approved, the 2024F after-savings load losses are forecast to decrease by 0.2 GWh due to decreased load. FBC has separated company use in the graph below, which is forecast at 13 GWh per year in 2024F, consistent with 2023S.

[10] MRP Application, Exhibit B-1-1, Appendix B3.

Figure 3-10: Normalized After-Savings Load Losses (GWh)



3.4.8 Peak Demand

The peak demand forecast is produced using the 10-year average of historical peaks, including peaks from the June 2021 "heat dome" event. The historical peak data is escalated by the gross load growth rate before it is averaged to account for the growth of demand on the FBC system.

Figures 3-11 and 3-12 below provide the historical winter peaks and summer peaks, respectively, from 2013 to 2022, as well as the estimates for 2023S and 2024F. To illustrate the non-weather-related growth in both winter and summer peaks over the last 10 years, the historical winter and summer peaks shown between 2013 and 2022 in Figures 3-11 and 3-12 below are weather-normalized and after-savings.

Furthermore, the peaks shown in both figures below are seasonal, i.e., the winter peak can fall in any month between November of the current year and February of the following year, and the summer peak can fall in any month between June and August.

Figure 3-11: After-Savings Winter Peaks (MW)

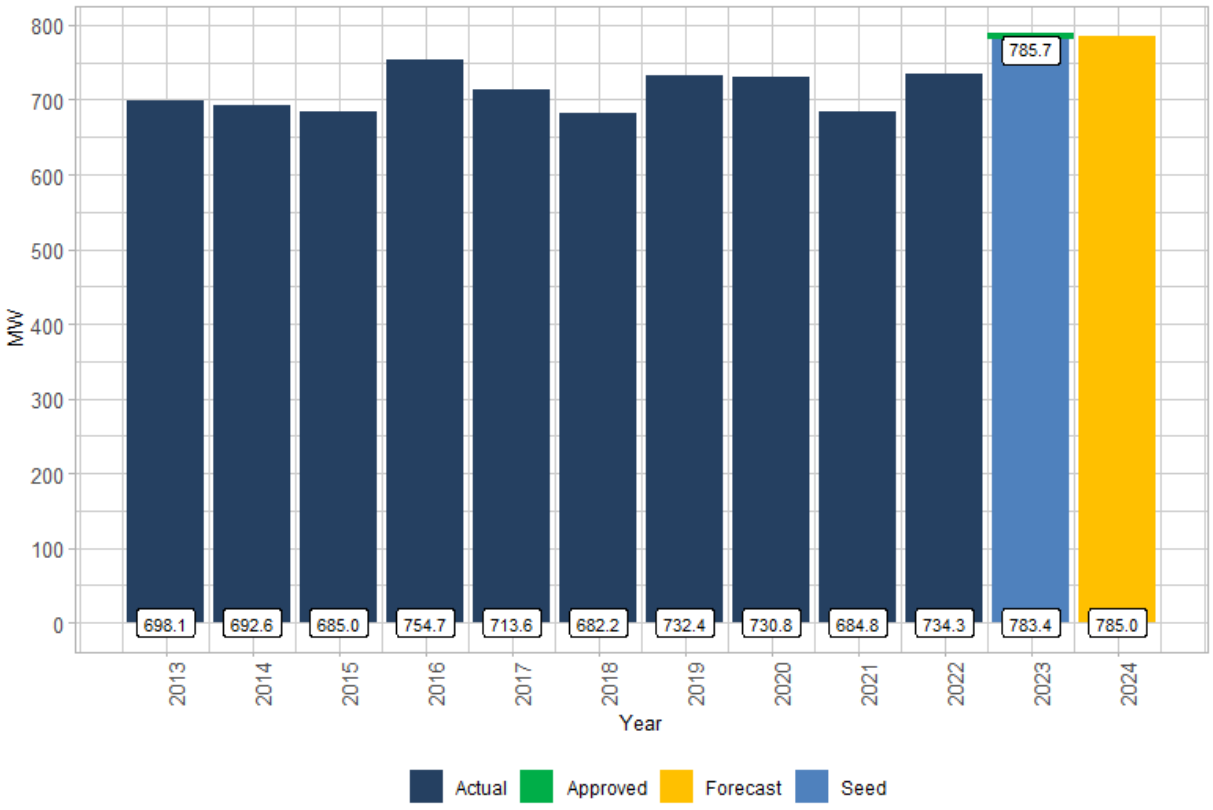
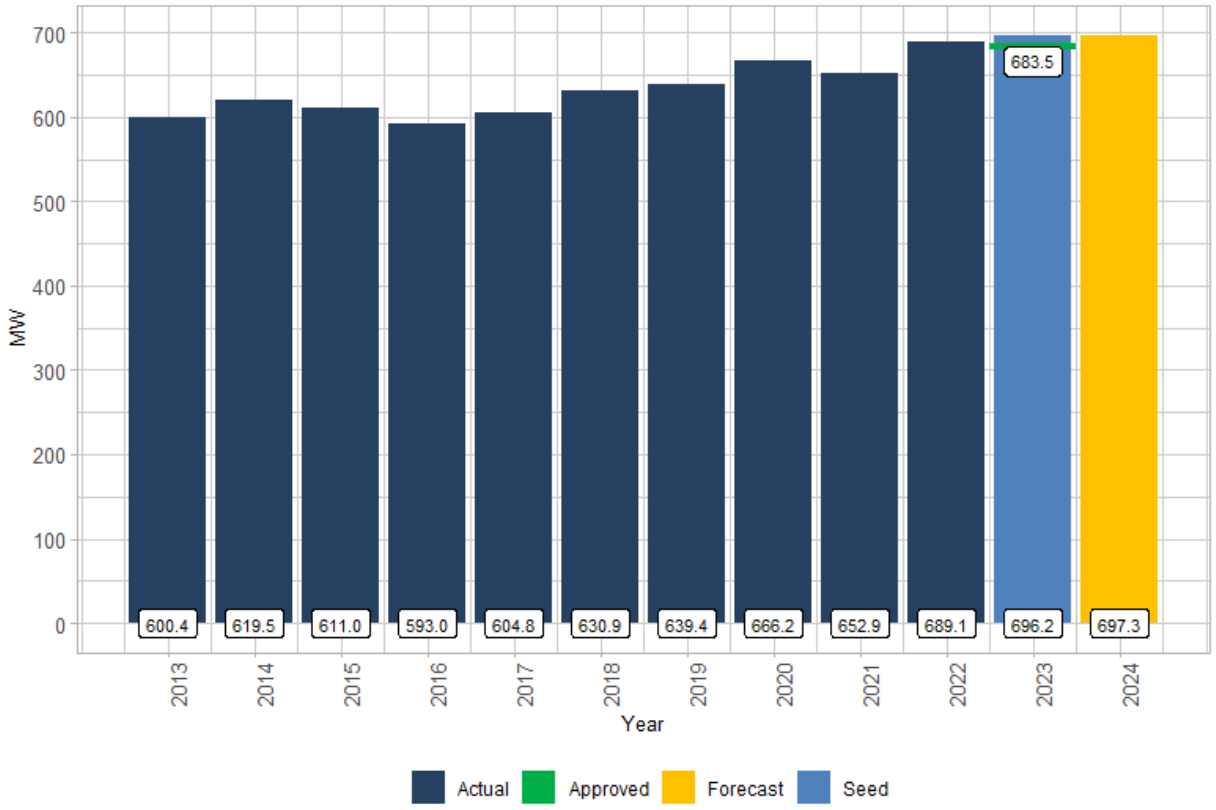


Figure 3-12: After-Savings Summer Peaks (MW)



3.5 CUSTOMER FORECAST

Table 3-3 shows the actual and forecast year-end customer counts by rate class. The residential and commercial customer counts are forecast using the methods described in Sections 3.4.1 and 3.4.2. Industrial customers are forecast based on information on expected new loads provided by key account managers. The lighting customer forecast is prepared using a five-year regression of year-end customer counts. Wholesale and irrigation customer counts are assumed to remain at 2022 levels.

Overall, for 2024F, FBC is forecasting customer growth of 1.5 percent compared to 2023S and growth of 0.7 percent compared to 2023 Approved.

Table 3-3: Customer Forecast[11]

Line No.	Description	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023S	2024F
1	Residential	111,862	113,431	114,166	115,772	117,748	120,291	122,465	124,966	126,678	129,131	131,323	133,291
2	Commercial	13,662	14,363	14,976	15,073	15,398	15,678	15,956	16,165	16,594	16,773	16,930	17,290
3	Wholesale	6	6	6	6	6	6	6	6	6	6	6	6
4	Industrial	47	49	50	50	50	52	51	43	42	42	42	42
5	Lighting	1,644	1,620	1,590	1,559	1,511	1,482	1,467	1,443	1,407	1,380	1,357	1,330
6	Irrigation	1,097	1,103	1,095	1,090	1,080	1,078	1,082	1,091	1,103	1,103	1,103	1,103
7	**Total**	128,318	130,572	131,883	133,550	135,793	138,587	141,027	143,714	145,830	148,435	150,761	153,063

3.6 RATE SCHEDULE 96 EV DCFC SERVICE FORECAST

On July 14, 2021, the BCUC issued Order G-215-21, which concluded that FBC's EV DCFC stations are prescribed undertakings under section 5 of the GGRR and approved flow-through treatment for the cost of service associated with the charging stations. By Order G-341-21 dated November 24, 2021, the BCUC approved the depreciation rate for the EV charging stations, and the inclusion of related revenues and expenses in FBC's regulated accounts. Following FBC's clarification on November 29, 2021 for the electricity input cost as directed in Decision and Order G-341-21, the BCUC approved the RS 96 rates on a permanent basis, by Order G-350-21 dated November 30, 2021, which include a time-based levelized rate[12] of $0.26 per minute and $0.54 per minute for FBC's 50 kW and 100 kW EV DCFC stations, respectively. FBC currently has a total of 42 EV DCFC stations in service across 22 sites and no additional stations are planned for 2023 or 2024.

As part of the Annual Review for 2022 Rates Decision and Order G-347-21[13], FBC was directed to:

- Provide an update on its EV DCFC charging stations' costs and revenues for the previous fiscal year along with a forecast of costs and revenues for the test period in future Annual Review filings.

Table 3-4 below provides the 2018 to 2022 Actual (i.e., previous fiscal years), 2023 Projected, and 2024 Forecast charging minutes and the resulting RS 96 revenues. Consistent with the approach presented in FBC's Revised and Updated EV DCFC Service Application dated September 30, 2020, the 2023 Projected and 2024 Forecast of charging minutes were determined based on the growth rates for ZEV sales targeted in the *BC ZEV Act*. These targets are 10 percent of ZEV sales by 2025, 30 percent by 2030, and 100 percent by 2040.[14]

[11] Direct customers only, i.e., excludes indirect wholesales customer counts.
[12] Including 15 percent transaction fees from FBC's EV DCFC vendor (i.e., AddEnergie, operator of the FLO EV charging network).
[13] Page 32.
[14] FBC's Revised and Updated EV DCFC Application, BCUC IR1 8.4 and CEC IR1 8.2. Additionally, as discussed in the RS 96 Assessment Report dated December 29, 2022, for forecasting purposes, FBC assumed the growth rates remain the same but are delayed by one year due to the COVID-19 pandemic.

It can be seen from Table 3-4 below that since the inception of FBC's charging stations (i.e., 50 kW in 2018 and 100 kW in 2021), the utilization rate has continued to grow, including in 2020 and 2021 when travel restrictions were in place due to the COVID-19 pandemic. Table 3-4 below also shows that there was a material increase in charging minutes from 2021 to 2022, which coincides with the ending of the aforementioned travel restrictions. FBC is expecting the upward trend will continue into 2024 with the growing number of electric vehicles available in the market. The upward trend that FBC is seeing with its EV DCFC service is consistent with the growth rates developed based on the ZEV sales targets used for the purpose of forecasting the charging minutes.

Table 3-4: FBC RS 96 EV DCFC Forecast

Line No.	Description	Actual 2018	Actual 2019	Actual 2020	Actual 2021	Actual 2022	Projected 2023	Forecast 2024
1	RS 96 Charging Minutes							
2	50 kW	15,309	94,386	110,504	229,342	410,783	584,194	782,820
3	100 kW	-	-	-	16,539	54,933	111,234	149,053
4	Total (Minutes)	15,309	94,386	110,504	245,881	465,716	695,428	931,874
5								
6	RS 96 Revenue, excl. 15% fee ($ millions)	$ 0.004	$ 0.024	$ 0.028	$ 0.058	$ 0.116	$ 0.180	$ 0.241

Table 3-5 below provides the cost of FBC's EV DCFC service for 2022 Actual, 2023 Projected and 2024 Forecast, including the RS 96 revenues shown in Table 3-4 above, and the prior years' surplus from 2018 to 2021.

FBC is currently forecasting a cumulative deficiency of $0.932 million from 2018 to 2024, including the 2024 forecast costs and revenue. FBC notes that the current RS 96 rates are set on a levelized basis which are designed to fully recover the forecast cost of service of the charging stations over the life of the stations, as such, deficiencies are expected in the early years of the service offering. Also contributing to the cumulative deficiency to date is the impact of the COVID-19 pandemic from 2019 to 2021 on the utilization of FBC's charging stations. As mentioned above, there has been a significant increase in the utilization of FBC's charging stations since 2022 and FBC expects the growth will continue. Furthermore, consistent with the approach in the Annual Review for 2023 Rates, FBC does not forecast revenue from the sale of carbon credits for future years due to the uncertainty in the timing of the credit validation as well as the market pricing. As such, FBC is not forecasting any carbon credit revenues in 2024. Please refer to Section 5.8 for further discussion of the carbon credits associated with FBC's EV DCFC stations which are recorded as Other Revenue. FBC expects the monetization of carbon credits will continue, which should help to reduce the overall deficiency in the future.

Table 3-5: EV DCFC Stations Costs and Revenues for 2022 Actual, 2023 Projected, and 2024 Forecast ($ millions)

Line No.	Description	Actual 2022	Projected 2023	Forecast 2024	Cumulative
1	Cost of Energy	0.136	0.177	0.197	
2	O&M	0.213	0.181	0.310	
3	Depreciation	0.456	0.551	0.593	
4	Amortization of CIAC	(0.190)	(0.236)	(0.249)	
5	Other Revenue - Carbon Credits	(0.744)	(0.544)	-	
6	Income Tax	(0.007)	0.048	0.132	
7	Earned Return	0.170	0.192	0.200	
8	Total Cost of Service	0.035	0.370	1.183	
9	RS 96 Revenue	(0.116)	(0.180)	(0.241)	
10	(Surplus) / Deficiency	(0.081)	0.190	0.942	1.050
11	Prior Year 2018-2021 (Surplus)/Deficiency				(0.119)
12	Cumulative (Surplus) / Deficiency				0.932

The RS 96 revenue (i.e., Line 9 of Table 3-5 above) is part of FBC's commercial sales revenue as presented in Section 3.7 below. Please also refer to Section 6.3.4 for a discussion of the forecast O&M expenses and Section 7.2.2 for a discussion of the forecast capital expenditures for the EV DCFC stations. Once the capital expenditures are included in rate base, they impact the depreciation, amortization of CIAC, income tax and earned return related to the EV DCFC stations that are shown in Table 3-5 above.

As directed by Order G-341-21, FBC filed a detailed assessment of the EV DCFC service on December 29, 2022 (RS 96 Assessment Report), which was accepted by the BCUC on June 19, 2023 by Letter L-33-23. As part of the RS 96 Assessment Report, FBC committed to providing an updated RS 96 Assessment Report by December 31, 2023, if an application for energy-based rates is not filed with the BCUC prior to this date.

3.7 REVENUE FORECAST

The forecast of revenues has been developed by applying approved 2023 rates to the forecast billing determinants for each customer class. Table 3-6 below summarizes the 2023 Approved, 2023 Projected and 2024 Forecast sales revenue. The commercial sales revenue shown in Table 3-6 below also includes the revenue from FBC's RS 96 EV DCFC stations discussed in Section 3.6.

Table 3-6: Forecast Sales Revenue at Approved Rates ($ millions)

Line No.	Description	Approved 2023	Projected 2023	Forecast 2024
1	Residential	$ 205.734	$ 208.939	$ 206.007
2	Commercial	110.490	111.741	110.808
3	Wholesale	54.100	55.279	55.574
4	Industrial	49.759	49.797	49.800
5	Lighting	2.295	2.298	2.221
6	Irrigation	3.695	3.666	3.967
7	Total	$ 426.073	$ 431.720	$ 428.377

When comparing the 2023 Projected to 2023 Approved, there is an increase in revenue of $5.647 million, primarily due to increases from the residential customer class, followed by increases from the commercial and wholesale customer classes.

For 2024, despite FBC forecasting a small reduction in net load of approximately 1 GWh (reduction in gross load of 2 GWh), FBC is forecasting an increase in revenue of $2.304 million when compared to 2023 Approved. The increase in revenue between 2024 Forecast and 2023 Approved is primarily due to the forecast increase in load from the wholesale customers as well as a forecast increase in residential and commercial customer counts (resulting in a small increase in the fixed monthly/bi-monthly customer charge). These increases are partially offset by reduced revenue from variable charges (i.e., $ per GWh) due to the forecast reduction in load from residential, industrial, and irrigation customers.

Variances between the revenue forecast in this section and the actual revenues realized are captured in the Flow-through deferral account.

3.8 SUMMARY

FBC is forecasting a decrease in consumption in 2024 compared to 2023 Approved. The 2024F gross load is forecast to be approximately 3,773 GWh, which is a 2 GWh decrease compared to the 2023 Approved gross load. Although the forecast load is decreasing in 2024, FBC is forecasting 2024 revenue to be $428.377 million, which is an increase of $2.304 million from 2023 Approved. This increase in revenue is primarily due to the forecast increase in load from the wholesale customers as well as an increase in residential and commercial customer counts (resulting in a small increase in the fixed monthly/bi-monthly customer charge), which is partially offset by reductions in load from residential, industrial, and irrigation customers.

4. POWER SUPPLY

4.1 INTRODUCTION AND OVERVIEW

This section includes a review of the 2023 Projected and 2024 Forecast power purchase expense (PPE), wheeling expense and water fees. Collectively, the PPE, wheeling expense and water fees are referred to as the power supply cost.

As shown in Table 4-1 below, the 2024 Forecast power supply cost of $193.532 million represents an increase of 6.3 percent or $11.427 million compared to the 2023 Approved cost of $182.105 million. The increase in 2024 Forecast power supply cost is driven primarily by the increase in PPE, although wheeling and water fee expenses have increased as well. The increase in the 2024 Forecast PPE is primarily the result of increased purchase rates for power. The 2024 Forecast wheeling expense has increased as a result of rates, partially offset by lower use. The 2024 Forecast water fee expense has increased compared to 2023 Approved as a result of rates and use.

Any variances between forecast and actual power supply costs are recorded in the Flow-through deferral account and returned to or recovered from customers in the subsequent year.

Table 4-1: Power Supply Cost ($ millions)

Line No.	Description	Approved 2023	Projected 2023	Forecast 2024
1	Power Purchase Expense	$ 163.575	$ 170.873	$ 173.694
2	Wheeling Expense	$ 6.987	$ 7.294	$ 7.324
3	Water Fees	$ 11.543	$ 12.433	$ 12.513
4	Total Power Supply Cost	$ 182.105	$ 190.600	$ 193.532
5				
6	Gross Load (GWh)	3,775	3,813	3,773

4.2 SUMMARY OF POWER SUPPLY RESOURCES

FBC uses a combination of Company-owned generation entitlements, firm contracted supply, and market purchases to meet its load requirements. The Company's firm resources consist of:

1. Canal Plant Agreement (CPA) Entitlements associated with the generation facilities owned by FBC. The costs associated with FBC-owned generation are not included in the power purchase estimates, except for the Balancing Pool adjustments, which account for year-to-year timing differences in the entitlement energy storage under the CPA;
2. The Brilliant Power Purchase Agreement (BPPA), a 125 MW contract (Order E-7-96), and an amendment to the BPPA which reflects the purchase of 20 MW of Brilliant Upgrade power (Letter L-57-00), and the 5 MW Brilliant Tailrace Capacity agreement (Order E-17-01);

3. A power purchase agreement (PPA) with BC Hydro (a 200 MW contract) under BC Hydro RS 3808 (Order G-60-14);

4. The Waneta Expansion Capacity Purchase Agreement (WAX CAPA), which is a 40-year purchase agreement with the Waneta Expansion Limited Partnership for capacity entitlements under the CPA (Orders E-29-10 and E-15-12);

5. A number of small Independent Power Producer (IPP) contracts; and

6. A number of market purchase arrangements.

4.3 PORTFOLIO OPTIMIZATION

The primary objectives of FBC's power supply portfolio planning are:

1. to ensure that the Company has sufficient firm resources to meet expected load requirements;

2. to ensure the availability of cost-effective reliable power for FBC's customers;

3. to prudently manage exposure to the cost and availability of market power supplies; and

4. to optimize the value of any surplus resources that are not needed to meet load requirements.

The Company currently has long-term, firm resources from which it can supply most of its forecast annual energy and capacity requirements. FBC's long-term, firm resources are capable of meeting FBC's forecast capacity requirements with the exception of June and a small number of hours during July. Consistent with the capacity self-sufficiency policy in FBC's 2021 Long Term Electric Resource Plan (LTERP), FBC will procure forward market blocks to cover these shortfalls on a planning basis. In addition, FBC is now forecasting small energy shortfalls emerging in November and December starting in 2024. Consistent with the accepted 2023/24 Annual Electric Contracting Plan (AECP), FBC will purchase winter energy blocks to address tightening winter energy supply and mitigate exposure to potential extreme spot market prices, should load exceed expected levels.

FBC's contracted resources, in particular the BC Hydro PPA, provide the Company some flexibility to participate in the market when conditions are favourable to mitigate the cost of holding these firm resources. However, over the past several years, the regional electricity market has been in a state of consistently higher prices compared to recent historical levels. This is due to several factors that include resource adequacy concerns, increased natural gas prices, and increased severe weather events. This change in the market price environment has resulted in little opportunity to displace Tranche 1, nominated PPA purchases on a forward basis.

Furthermore, although FBC's load requirements are forecast to grow over time, the amount of capacity provided under the WAX CAPA is currently greater than FBC's capacity requirements in

most months, and FBC sells the surplus capacity to mitigate power purchase expense. FBC has contracted to release a 50 MW block of capacity purchased under the WAX CAPA to BC Hydro under the Residual Capacity Agreement (RCA), which was approved by Order G-161-14. The remaining surplus WAX CAPA will be sold to Powerex Corp. (Powerex) on a day-ahead basis, if and when it is not required to meet FBC load requirements. These sales are made under the Capacity and Energy Purchase and Sale Agreement (CEPSA) with Powerex dated February 17, 2015, and accepted by Order E-10-15.

4.4 FBC 2023/24 ANNUAL ELECTRIC CONTRACTING PLAN

On April 28, 2023, FBC filed its 2023/24 AECP with the BCUC. The purpose of the AECP is to outline FBC's plan to meet its peak demand requirements and annual energy requirements for the operating year commencing October 1, 2023 and ending September 30, 2024, and to facilitate FBC's annual energy nomination under the PPA. FBC is required to take or pay for 75 percent of the PPA Nomination, regardless of whether it schedules the energy. The difference between the PPA Nomination and the 75 percent minimum take provides flexibility to manage annual loads that are below forecast or to displace PPA purchases with lower cost market purchases. Therefore, real-time opportunities to displace PPA purchases are restricted to a maximum of 25 percent of the PPA nominated energy, but could be more or less, depending on system conditions.[15] The AECP also outlines FBC's load and resource balance over the following four years, and FBC's plan for optimizing its portfolio over that period. FBC's forecasts of PPE for the remainder of 2023 and for 2024 are based on the plan detailed in the 2023/24 AECP, which was accepted by the BCUC on June 1, 2023, by Letter L-24-23.[16]

The AECP identified FBC's intention to make its annual energy nomination under the PPA for the 2023/24 contract year equal to 929 GWh, less any firm market contracts that FBC could enter, as described in Section 5 of the 2023/24 AECP. Prior to the June 30, 2023 nomination deadline, FBC updated its forecast load and resource balance for the 2023/24 contract year and submitted a nomination of 929 GWh.

4.5 2023 PROJECTED POWER PURCHASE EXPENSE

As shown in Table 4-2 below, FBC's 2023 Projected gross load (after taking into account demand side management and other customer savings) is expected to be 38 GWh above the 2023 Approved value, and PPE is projected to be above the 2023 Approved value by $7.298 million. The rise in 2023 Projected PPE is primarily due to increased Market and Contracted Purchase expense as a result of increased volumes and rates.

[15] For example, if loads were 50 GWh lower in a year than forecast, that must be adjusted for as part of the 25 percent PPA flexibility such that the amount of PPA energy that can be displaced by market purchases is also reduced by 50 GWh.

[16] The AECP was filed confidentially. The non-confidential Executive Summary is attached to Letter L-24-23.

A majority of the increase in volume and cost was due to FBC purchasing wholesale market power from the spot market, at rates economic to the PPA during the first six months of the year to reduce required purchases above the BC Hydro PPA Nomination. In contrast, there was a relatively small amount of wholesale market contracts included in the 2023 Approved figures, as forward market contract prices resulted in little opportunity to displace PPA on a forward basis. In addition, FBC purchased forward market blocks to cover projected capacity shortfalls in June 2023 and reduce exposure to Tranche 2 energy under the PPA with BC Hydro. Also included in the Projected 2023 expense are planned wholesale market purchases in November and December 2023, consistent with the strategy presented in the 2023/24 AECP.

While forecast market savings included in the 2023 Approved[17] did materialize during the first six months of the year, FBC has not included any forecast savings for the remainder of 2023 within the Projected PPE. This is due to the current forward market price premium compared to rates for PPA purchases for the remainder of 2023.

Partially offsetting the increase in PPE is a reduction to the Waneta Expansion Expense due to increased forecast surplus sales revenue under the RCA and CEPSA.

Table 4-2: 2023 Power Purchase Expense ($ millions)

Line No.	Description	Approved 2023	Projected 2023	Difference
1	Brilliant	$ 44.050	$ 44.048	$ (0.002)
2	BC Hydro PPA	71.302	70.702	(0.600)
3	Waneta Expansion	41.834	38.351	(3.483)
4	Market and Contracted Purchases	6.326	18.624	12.297
6	Independent Power Producers	0.062	0.195	0.133
7	Self-Generators	-	0.044	0.044
8	CPA Balancing Pool	(0.000)	(1.570)	(1.570)
9	Transmission Service Loss Recoveries	-	-	-
10	Special and Accounting Adjustments	-	0.479	0.479
11	Total	$ 163.575	$ 170.873	$ 7.298
12				
13	Gross Load (GWh)	3,775	3,813	38

4.6 2024 FORECAST POWER PURCHASE EXPENSE

As shown in Table 4-3 below, the 2024 Forecast PPE is $2.821 million above the 2023 Projected. The forecast increase from $170.873 million in 2023 to $173.694 million in 2024 is primarily a result of an increase in BC Hydro PPA expenses and escalation of Waneta Expansion rates. This is partially offset by a decrease in Market and Contracted Purchases due to volume. FBC is increasingly reliant on energy supplied by BC Hydro as it is generally more cost effective than the market during most times of the year. However, FBC also requires wholesale market purchases

[17] 2023 Approved included $7.000 million in potential real-time opportunities, including $3.500 million forecast for the first six months. FBC was able to exceed the $3.500 million during the first six months of 2023 but does not expect any further savings for the remainder of 2023.

to address supply gaps and reduce exposure to potentially extreme market prices, beyond what can be supplied by the PPA. Escalations to the Brilliant contract rates are also contributing to increased costs.

Table 4-3 below shows a comparison of the 2023 Projected and 2024 Forecast PPE. Reasons for significant variances from the 2023 Projected PPE are discussed below.

Table 4-3: 2024 Forecast Power Purchase Expense ($ millions)

Line No.	Description	Projected 2023	Forecast 2024	Difference
1	Brilliant	$ 44.048	$ 44.433	$ 0.385
2	BC Hydro PPA	$ 70.702	71.680	0.978
3	Waneta Expansion	$ 38.351	40.365	2.014
4	Market and Contracted Purchases	$ 18.624	16.972	(1.652)
5	Independent Power Producers	$ 0.195	0.245	0.050
6	Self-Generators	$ 0.044	-	(0.044)
7	CPA Balancing Pool	$ (1.570)	0.000	1.570
8	Transmission Service Loss Recoveries	-	-	-
9	Special and Accounting Adjustments	$ 0.479	-	(0.479)
10	Total	$ 170.873	$ 173.694	$ 2.821
11				
12	Gross Load (GWh)	3,813	3,773	(40)

4.6.1 Brilliant

Brilliant expense is forecast to increase in 2024 by $0.385 million compared to 2023 Projected due to increased rates, which are based on a forecast of the operating and maintenance cost of the plant, as well as a true-up to the prior year's actual costs compared to forecast.

4.6.2 BC Hydro PPA

BC Hydro PPA expense is forecast to increase in 2024 by $0.978 million compared to the 2023 Projected expense. The drivers of the variance are a higher purchased volume (62 GWh), which increases the expense by $4.046 million, offset by a lower average purchase rate for BC Hydro PPA,[18] which accounts for a decrease of $0.068 million, for a total increase of $3.978 million. FBC has decreased its 2024 Forecast of PPA expense by $3.000 million in savings to account for potential real-time opportunities to displace PPA purchases with lower cost market purchases. The 2023 Projected BC Hydro expense does not include any adjustment for potential real-time opportunities for the remainder of 2023. This results in a variance between 2023 Projected and 2024 Forecast of $0.978 million[19], as shown in Table 4-3. Actual market savings for the remainder of 2023 and 2024 may be higher or lower and will depend on system and market conditions at

[18] A higher PPA nomination for the 2023/24 contract year results in less penalty charges from energy taken over and above the PPA nomination and a lower average BC Hydro PPA purchase rate.

[19] $0.978 million is calculated as follows: Total increase of $3.978 million less the $3.000 million 2024 Forecast real-time opportunities.

the time. Any variance, including these savings, is recorded in the Flow-through deferral account and returned to or recovered from customers in a subsequent year.

4.6.3 Waneta Expansion

The $2.014 million increase in Waneta Expansion expense is due to the 2.1 percent annual fixed escalation of WAX CAPA rates, and a $0.549 million decrease in forecast surplus sales revenue under the RCA and CEPSA. Revenue under the CEPSA is linked to the amount of capacity FBC releases to Powerex and the day-ahead market prices at the Mid-Columbia River (Mid-C) trading hub. The Mid-C is the largest electricity trading hub in the Pacific Northwest and is located on the US portion of the Columbia River. CEPSA revenue is forecast using the average monthly sales revenue from the past three years. The forecast of surplus capacity sales revenue in 2024, which is included in Line 3 of Table 4-3, is approximately $13.636 million.

4.6.4 Market and Contracted Purchases

The $1.652 million decrease in Market and Contracted Purchases forecast for 2024 is a result of reduced volume when compared to 2023 Projected. Market and Contracted Purchases for 2023 Projected include fixed price contracted purchases, year to date real-time market purchases and forecast purchases in November and December 2023 at forward market rates. Market purchases included in the 2024 Forecast include fixed price contracted purchases, as well as forecast wholesale market purchases at current forward market rates to cover energy requirements in January, February, November and December, and capacity shortfalls in June and July 2024. Forecast real-time market purchases for Rate Schedule 37[20] load are also included. As discussed above in the BC Hydro PPA variance explanation, there may be opportunities for additional real-time market purchases using the flexibility of the PPA purchases.

4.6.5 CPA Balancing Pool

The CPA Balancing Pool represents timing differences in entitlement energy storage under the CPA and is used to manage fluctuations in load and resource availability, or to take advantage of market opportunities. In the 2023 Projected PPE, FBC has stored a net total of 31 GWh of entitlement energy, valued at $1.570 million. For the 2024 Forecast, and consistent with past practice, FBC does not forecast any net use or storage of entitlement energy.

4.7 TRANSMISSION SERVICE LOSS RECOVERIES

Transmission service customers taking service under FBC's Rate Schedules 100 and 101 currently physically deliver energy to FBC to compensate for the losses that are incurred on FBC's system as a result of wheeled energy. FBC includes transmission wheeling losses in its load

[20] RS 37 is large commercial stand-by service, which is an on-demand back-up and maintenance service provided to self-generating customers. This service is provided to the customer at an hourly market-based rate, reflective of FBC's cost of supply. FBC procures this supply on a real-time basis because there is little certainty as to when customers will use this service. Forecast RS 37 load for 2024 is 15 GWh or 0.4 percent of total gross load.

forecast (included in Tables 4-2 and 4-3, Line 8), and also includes loss recovery as a firm resource. Because the recoveries are delivered physically, there is no associated cost or revenue. Table 4-4 shows the 2023 and 2024 loss recoveries.

Table 4-4: Transmission Service Loss Recoveries (GWh)

Line No.	Description	Approved 2023	Projected 2023	Forecast 2024
1	Loss Recoveries	12	12	12

4.8 WHEELING EXPENSE

Wheeling expense includes wheeling service provided by BC Hydro under the Amended and Restated Wheeling Agreement (ARWA) and Open Access Transmission Tariff (OATT) as needed to supply the Company's loads in the Okanagan, Creston and Princeton. Also included are charges paid to Teck Metals Ltd. (Teck) for the use of its 71 Line. Rates under the ARWA are specified in BC Hydro's RS 3817.

Wheeling expense is forecast using the same method as in the Annual Review for 2023 Rates.[21] Table 4-5 below shows FBC's Wheeling Expense for 2023 and 2024.

Table 4-5: Wheeling Expense ($ millions)

Line No.	Description		Approved 2023	Projected 2023	Forecast 2024
1	Wheeling Nomination (MW Months)				
2	Okanagan Point of Interconnection		2,670	2,670	2,595
3	Creston		420	420	450
4					
5	Wheeling Expense				
6	Okanagan Point of Interconnection	$	5.555	5.786	5.813
7	Creston		0.570	0.593	0.658
8	Other		0.863	0.914	0.854
9	Total Wheeling Expense	$	6.987	7.294	7.324

Total 2023 Projected wheeling expense is $0.307 million greater than 2023 Approved. The 2023 Projected ARWA costs are $6.380 million (Lines 6 and 7 in the table above), a $0.255 million increase when compared to 2023 Approved, which is a result of higher than expected BC-CPI and therefore ARWA rates. 2023 Projected Teck and OATT wheeling costs are $0.914 million (Line 8 above), which is $0.051 greater than 2023 Approved. This is mainly due to increased use of OATT wheeling.

[21] ARWA expense is forecast using known volumes and prior year's rates escalated by estimated BC-CPI. Teck wheeling is forecast based on the previous year's costs and escalated by 2 percent annually per contract. OATT wheeling costs are estimated using an average of prior years' expenses.

2024 Forecast wheeling expense is $0.030 million higher than 2023 Projected. This is a result of increased rates. FBC decreased the ARWA Okanagan wheeling nomination to 2,595 MW months in 2024 from 2,670 MW months in 2023. ARWA rates are forecast to increase on October 1 of both 2023 and 2024 based on forecast BC-CPI, as is the Teck wheeling rate as a result of a letter agreement made between Teck and FBC.

4.9 WATER FEES

Water fees are based on FBC's entitlement usage in the previous year and the rate increases are indexed to BC-CPI.

As shown in Table 4-6 below, the 2024 Forecast water fees are increasing by $0.080 million from the 2023 Projected due to increased rates.

Table 4-6: Water Fees ($ millions)

Line No.	Description	Approved 2023	Projected 2023	Forecast 2024
1	Plant Entitlement in Previous Year (GWh)	1,571	1,585	1,561
2				
3	Water Fees	$ 11.543	$ 12.433	$ 12.513

4.10 SUMMARY

FBC's forecast of PPE is based on FBC's firm resources in place at the time of filing, as well as forecast market purchases, and is consistent with the 2023/24 AECP. Any variances in the power supply cost, including any decreases in PPE due to further portfolio optimization, are recorded in the Flow-through deferral account and returned to or recovered from customers in a subsequent year.

5. OTHER REVENUE

5.1 INTRODUCTION AND OVERVIEW

This section discusses FBC's forecasts of Other Revenue. In the MRP Decision (page 74), FBC was approved for variances between forecast and actual Other Revenue to be subject to earnings sharing.[22]

FBC is forecasting Other Revenue for 2024 to be $0.149 million lower than 2023 Approved, primarily due to lower Contract Revenue and Transmission Access Revenue.

2023 Projected Other Revenue is $0.622 million higher than 2023 Approved. The main drivers of this increase are the sales of carbon credits related to Electric Vehicle (EV) Direct Current Fast Charging (DCFC) stations, as well as higher Contract Revenue.

Table 5-1: Other Revenue ($ millions)

Line No.	Description	Approved 2023	Projected 2023	Forecast 2024
1	Apparatus and Facilities Rental	$ 6.108	$ 6.108	$ 6.199
2	Contract Revenue	2.367	2.591	2.260
3	Transmission Access Revenue	1.834	1.716	1.723
4	Interest Income	0.030	0.035	0.037
5	Late Payment Charges	0.994	0.961	0.962
6	Connection Charges	0.553	0.553	0.561
7	EV Stations Carbon Credits	-	0.544	-
8	Other Recoveries	0.355	0.355	0.351
9	Total Other Revenue	$ 12.241	$ 12.863	$ 12.092

In the following sections, FBC summarizes its projections and forecasts for each of the line items included in the table above.

5.2 APPARATUS AND FACILITIES RENTAL

Apparatus and Facilities Rental is comprised primarily of pole contact revenue from other utilities and businesses that attach their facilities to FBC infrastructure in order to deliver services to their customers, such as telephone and cable television providers. Rent is charged at a unit rate per pole contact multiplied by the number of poles that are contacted. There are no variances projected in 2023 compared to 2023 Approved, as final amounts have yet to be calculated since the majority of invoices are issued during the third quarter of the year. The 2024 Forecast is higher than 2023 Approved due to expected escalations in unit rental rates for continuing contracts.

[22] Variances in Other Revenue associated with Electric Vehicle (EV) stations carbon credits are treated as flow-through, as EV Direct Current Fast Charging (DCFC) stations are prescribed undertakings under section 5 of the GGRR and the cost of service associated with EV DCFC stations is subject to flow-through treatment.

5.3 CONTRACT REVENUE

FBC performs work under contract to third parties at the Waneta and Brilliant hydroelectric generating facilities. This third-party work, and the associated management fees earned, fluctuates from year to year based on customer requirements, which include routine and non-routine work planned at the start of the customer's fiscal year.

The Company also operates and maintains a number of other facilities for third-party entities through its non-regulated affiliate FortisBC Pacific Holdings Inc. (FPHI). Transactions between FBC and FPHI are conducted in accordance with FBC's Code of Conduct and Transfer Pricing Policy[23] and earn a transfer price profit revenue. Revenues may fluctuate from year to year depending on customer requirements.

The 2023 Projected revenue is higher than 2023 Approved due to higher expected transfer price profit revenue on facilities operated and maintained by FPHI, based on amounts earned so far in 2023. The 2024 Forecast is slightly lower than 2023 Approved due to less customer requirements expected as a result of a higher level of work performed in the last few years for one customer, which is expected to decrease the need for non-routine work.

5.4 TRANSMISSION ACCESS REVENUE

Transmission Access Revenue represents charges to customers for transmitting power over the FBC system. The 2023 Projected revenue is lower than 2023 Approved due to a lower nomination than originally forecast for one customer. The 2024 Forecast is also lower than 2023 Approved due to lower nominations expected.

5.5 INTEREST INCOME

Interest Income is primarily comprised of DSM loan interest income, as well as other banking interest income. The Company is not forecasting significant changes in the amount of DSM loans outstanding or cash balances on hand attracting interest; as a result, although higher interest rates are available, no significant changes in interest income are expected in 2023 Projected or the 2024 Forecast.

5.6 LATE PAYMENT CHARGES

As explained in the Annual Review for 2023 Rates, Late Payment Charges were historically forecast based on the average of the most recent three years of actual Late Payment Charges earned. However, due to a number of factors in the most recent years, including the COVID-19 pandemic and FBC's implementation of customer relief measures, the actual amounts collected have fluctuated significantly from year to year. As these fluctuations would still be present in the most recent three years of actual results (i.e., 2020, 2021 and 2022), FBC has utilized the same

[23] As approved by Order G-5-10A.

approach used to calculate the 2023 Approved Late Payment Charges in the 2023 Annual Review. Accordingly, the 2024 Forecast for Late Payment Charges is calculated based on the average of 2022 Actual Late Payment Charges of $0.962 million and 2023 Projected of $0.961 million. This results in a forecast decrease in Late Payment Charges of $0.032 million compared to 2023 Approved and is generally consistent with the 2023 Projected amount.

5.7 CONNECTION CHARGES

Connection Charges are calculated based on the fees specified in FBC's rate schedules applicable to new customer connections or current customer reconnections. The 2023 Projected is expected to be consistent with 2023 Approved based on amounts charged so far in 2023. The 2024 Forecast is expected to be slightly higher than 2023 Approved based on customer growth and forecast customer reconnections.

5.8 CLEAN GROWTH INITIATIVE – EV DCFC STATIONS CARBON CREDITS

As discussed in Section 3.6, FBC's EV DCFC stations are prescribed undertakings under Section 5 of the GGRR[24] and the cost of service associated with EV DCFC stations is subject to flow-through treatment. Please refer to Table 3-5 in Section 3.6 for a summary of EV DCFC station costs and revenues from 2022 Actual to 2024 Forecast.

The sale of the carbon credits related to EV DCFC stations[25] earned under the Renewable Low Carbon Fuel Requirements Regulation (RLCFRR) is recorded as Other Revenue in FBC's regulated accounts, which is embedded in the rate design of the EV DCFC stations.

FBC anticipates that 1,210 credits from the 2021 compliance period, with an approximate value of $0.544 million,[26] will be monetized prior to the end of 2023 and has therefore included this amount in 2023 Projected Other Revenue. Since FBC did not forecast any monetization of carbon credits in the 2023 Approved amount as part of the Annual Review for 2023 Rates, the variance between the 2023 Projected amount of $0.544 million and the 2023 Approved amount of zero will be captured in the Flow-through deferral account and returned to customers in 2024 rates. Consistent with the approach described in the Annual Review for 2023 Rates, FBC does not forecast revenue from the sale of credits for future years due to the uncertainty in the timing of the credit validation as well as the market pricing. As such, FBC is not forecasting any carbon credit revenues in 2024. As noted above, the cost of service associated with EV DCFC stations is subject to flow-through treatment. Therefore, any variances between actual and forecast sales

[24] Order G-215-21 dated July 14, 2021.

[25] Includes both public charging stations owned by FBC as well as public stations owned by other entities (metered commercial accounts) as discussed in Exhibit B-6 of FBC's Annual Review for 2022 Rates, BCSEA IR1 4.3. Beginning in 2022, FBC is only permitted to claim credits for charging stations owned by FBC. FBC does not currently claim credits for non-public EV charging services for either commercial or residential customers.

[26] 1,210 credits x $449.20 average Q1-2023 sales price (source: https://www2.gov.bc.ca/gov/content/industry/electricity-alternative-energy/transportation-energies/renewable-low-carbon-fuels/credits-market)

of carbon credits will be captured in the Flow-through deferral account and returned to customers in the subsequent year.

5.9 OTHER RECOVERIES

Other Recoveries are primarily comprised of fees earned on the recovery of costs for miscellaneous services, such as street light maintenance charged to municipalities and AMI radio-off meter read fees. There are no variances expected in 2023 Projected compared to 2023 Approved based on amounts recognized to date. The 2024 Forecast is expected to be slightly lower than 2023 Approved due to an expected reduction in AMI radio-off meter read fees resulting from a lower volume of customers choosing the radio-off option.

5.10 SUMMARY

FBC has forecast the Other Revenue components for 2024 reflecting all applicable contracts and fixed revenues, and based on the Company's best knowledge of the factors that drive the variable components. Variances in Other Revenue, with the exception of EV DCFC stations carbon credits, are shared with customers through the earnings sharing mechanism.

6. O&M EXPENSE

6.1 INTRODUCTION AND OVERVIEW

Under the MRP, FBC's O&M expense is primarily determined by formula, with the addition of a certain items that are forecast outside the formula on an annual basis.

In 2024, the formula O&M is $72.823 million, representing a 3.6 percent increase from the 2023 formula O&M, primarily due to the formula drivers. O&M expenses forecast outside the formula for 2024 are $1.499 million, representing a 36.2 percent decrease from the amount approved for 2023. Overall, the 2024 Forecast gross O&M expense is $74.322 million, which is an increase of approximately 2.3 percent from the 2023 Approved level.

The components of 2024 O&M expense are shown in Table 6-1 below.

Table 6-1: 2024 O&M Expense ($ millions)

Line No.	Description	Approved 2023	Projected 2023	Forecast 2024	Reference
1	Formula O&M	$ 70.318	$ 70.318	$ 72.823	Section 11, Schedule 20, Line 8
2	Forecast O&M	2.349	2.361	1.499	Section 11, Schedule 20, Line 20
3	Total Gross O&M	72.667	72.679	74.322	Line 1 + Line 2
4	Capitalized Overhead	(10.900)	(10.900)	(11.148)	Section 11, Schedule 20, Line 23
5	Net O&M	$ 61.767	$ 61.779	$ 63.174	Line 3 + Line 4

In the sections below, FBC provides further details on its formula and forecast O&M expenses for 2024. Additionally, in compliance with the BCUC's directive in the MRP Decision,[27] FBC provides information related to its System Operations, Integrity and Security expenditures in Subsection 6.2.1.

6.2 FORMULA O&M EXPENSE

The formula-driven portion of O&M starts from the prior year's Approved Base O&M per Customer (UCOM), escalated by the prior year's inflation less a productivity improvement factor of 0.5 percent, and then multiplied by 75 percent of the forecast growth in average customers, resulting in the current year inflation-indexed O&M before true-up. A true-up of formula O&M based on actual average customers from two years prior is then added to the current year inflation-indexed O&M.

As calculated in Section 2, the 2024 inflation based on prior year's BC-CPI and BC-AWE, less the productivity improvement factor, is 3.580 percent.

For 2024, the annual operating and maintenance expense under the formula is calculated as:

[27] MRP Decision, p. 118.

2023 Approved formula UCOM x [1 + (I Factor – X Factor)] x [Prior Year Average Customers + (0.75 x growth in average customers)] + 2022 Formula O&M True-up

Table 6-2 below shows the calculation of the 2024 Formula O&M, including the calculation of the 2022 Formula O&M true-up. FBC notes the true-up of formula O&M is a two-year lag based on actual average customer counts from 2022.

Table 6-2: Calculation of 2024 Formula O&M ($ millions)

Line No.	Description		Forecast 2024	Reference
1	Prior Year Base Unit Cost O&M ($/ customer)	$	472	G-382-22 FBC 2023 Annual Review
2	I-Factor		3.580%	Section 2, Table 2-3, Line 11
3	Current Year Unit Cost O&M ($/customer)	$	489	
4	Average Customer Forecast		148,984	Section 2, Table 2-3, Line 13
5	2024 Inflation-Indexed O&M before 2022 True-up	$	72.853	Line 3 x Line 4 / 1,000,000
6	2022 True-up O&M		(0.030)	Line 16
7	Inflation-Indexed O&M	$	72.823	Line 5 + Line 6
8				
9	2022 O&M True-up			
10	2022 Actual 12 month Average Customers		147,112	FBC 2022 Annual Report
11	2022 Forecast 12 month Average Customers		147,199	G-374-21 FBC 2022 Annual Review
12	Difference		(87)	Line 10 + Line 11
13	Growth Factor		75%	G-166-20 FBC MRP Decision
14	Change in Customers - True-up		(65)	Line 12 x Line 13
15	2022 Unit Costs	$	455	G-374-21 FBC 2022 Annual Review
16	O&M True-up for 2024	$	(0.030)	Line 14 x Line 15 / 1,000,000

6.2.1 New/Incremental System Operations, Integrity and Security Funding

In the MRP Decision (page 118), the BCUC directed FBC to provide in each Annual Review a breakdown and explanation of both annual and cumulative variances between forecast/actual and formula O&M related to the approved new/incremental System Operations, Integrity and Security funding, and quantify the variances attributable to the following areas: tree management; generation dam safety; network operations apprentice program; cyber security; data analytics; and any other significant factors or miscellaneous items.

The table below shows the requested information, including the new/incremental funding in each category for 2022 Formula O&M, 2022 Actual O&M, and the resulting variances, as well as the Cumulative Forecast/Actual variance for the first three years of the MRP.

Table 6-3: System Operations, Integrity and Security New/Incremental Spending ($ millions)

Line No.	Description	2022 Formula O&M	Actual 2022 O&M	2022 Forecast/Actual Variance	Cumulative Forecast/Actual Variance[2]
1	Tree Management	$ 0.083	$ 0.434	$ 0.352	$ 0.787
2	Generation Dam Safety	$ 0.256	$ 0.111	$ (0.145)	$ (0.007)
3	Network Operations Apprentice Program	$ 0.217	$ 0.245	$ 0.027	$ (0.140)
4	Cyber Security	$ 0.088	$ 0.264	$ 0.176	$ 0.426
5	Data Analytics	$ 0.109	$ -	$ (0.109)	$ (0.316)
6	Other	$ -	$ -	$ -	$ -
7	Total	$ 0.754	$ 1.054	$ 0.301	$ 0.750

Notes to Table:

[1] 2022 Formula O&M is the approved 2021 formula for incremental funding with Net Inflation factor applied (4.041%).
[2] Cumulative Forecast/Actual variance is the 2020, 2021 and 2022 Actual variance.

Overall, total actual spending in 2022 was $1.054 million, which is $0.301 million higher than the 2022 Formula O&M amount. Areas with notable variances include tree management, generation dam safety, cyber security and data analytics.

For tree management, FBC spent $0.352 million more than the formula amount to address an increased number of unhealthy trees as part of FBC's right-of-way management program.

For generation dam safety, FBC spent $0.145 million less than the formula amount primarily due to the completion of dam safety review activities in 2021. As explained in Section 6.2.1 of the Annual Review for 2023 Rates, FBC spent $0.199 million more than the formula amount in 2021 due to the continuation of dam safety review activities. The spending overall on these activities has been consistent with the formula amount, as the cumulative variance is only $0.007 million for the first three years of the MRP term (as shown in Table 6-3 above).

For cyber security, FBC spent $0.176 million more than the formula amount. The higher spending was for additional consulting resources in the following areas: an additional consulting resource to augment cybersecurity requirements due to additional threat management needs; emergency management consulting for emergency exercises; physical security threat intelligence services to manage security risk; and the use of consulting services to update the business continuity program.

In data analytics, FBC spent $0.109 million less than the formula amount in 2022 primarily due to labour savings from a delay in hiring. In 2022, the focus was on building solutions in business areas including providing enhanced reporting using dashboards. For further details, please refer to Section 1.4.2 of the Application.

For the first three years of the MRP, FBC spent $0.750 million more than the formula amount. Over the term of the MRP, FBC anticipates the total new/incremental spending required in the combined categories of System Operations, Integrity and Security will continue to be higher than the amount embedded in the formula. FBC will continue to manage this spending within its overall O&M spending envelope.

6.3 O&M EXPENSE FORECAST OUTSIDE THE FORMULA

In addition to FBC's formula O&M, FBC forecasts a number of O&M items outside of the formula annually, including pension and OPEB expense, insurance premiums, BCUC levies, and the cost of service associated with Clean Growth initiatives, such as Electric Vehicle (EV) charging stations, as well as the O&M impacts of any exogenous factor items. For 2024, FBC continues to include the incremental O&M resulting from the Mandatory Reliability Standards (MRS) Assessment Report No. 13 (AR13), which was approved for exogenous treatment in the Annual Review for 2022 Rates.

The 2024 amounts are shown in Table 6-4 below along with a comparison to 2023.

Table 6-4: 2024 Forecast O&M ($ millions)

Line No.	Description	Approved 2023	Projected 2023	Forecast 2024
1	Pension/OPEB (O&M Portion)	$ (1.297)	$ (1.297)	$ (2.532)
2	Insurance Premiums	2.457	2.507	2.678
3	BCUC Levies	0.385	0.385	0.458
4	Clean Growth Initiative - EV DCFC	0.219	0.181	0.310
5	Exogenous Factor - MRS	0.585	0.585	0.585
6	Total Forecast O&M	$ 2.349	$ 2.361	$ 1.499

Each of the items that is forecast outside of the formula is discussed below. Variances in pension and OPEB expense are captured in the Pension and OPEB Variance deferral account and variances in BCUC levies are captured in the BCUC Levies Variance deferral account. Variances in insurance premiums, the cost of service associated with EV charging stations, and exogenous factors are captured in the Flow-through deferral account.

6.3.1 Pension and OPEB Expense

Pension and OPEB expense for 2024 is based upon actuarial estimates using a range of assumptions as of December 31, 2022. In addition to O&M, pension and OPEB expense is embedded in capital expenditures, as shown in Table 6-5.

Table 6-5: Pension and OPEB Expense ($ millions)

Line No.	Description	Approved 2023	Projected 2023	Forecast 2024
1	O&M	$ (1.297)	$ (1.297)	$ (2.532)
2	Capital	1.888	1.888	1.875
3	Total Pension & OPEB Expense	$ 0.591	$ 0.591	$ (0.657)

The variance between the 2023 Approved/Projected and actual pension and OPEB expense is included in the Pension and OPEB Variance deferral account and amortized into rates over a three-year period, as approved by Order G-139-14.

The 2024 Forecast pension and OPEB expense is lower than 2023 Approved by $1.248 million. The difference is primarily due to the following factors:

- A decrease of approximately $1.7 million due to an increase in investment returns as a result of a higher balance of pension plan assets; and
- A decrease of approximately $0.3 million due to the US GAAP Pension & OPEB Transition Obligation non-rate base deferral account being fully amortized in 2023.

The above decreases are offset in part by:

- An approximate increase of $0.8 million in interest costs due to an increased discount rate, which is determined with reference to the market rate of interest on high-quality debt instruments at a point in time (a discount rate of 4.50 percent was used to determine the 2023 Approved expense compared to a discount rate of 5.25 percent used to determine the 2024 Forecast expense).

6.3.2 Insurance Premiums

The component of insurance expense tracked outside of formula O&M relates to the insurance premium expense allocated to FBC by Fortis Inc. as set out in Table 6-6 below.

Table 6-6: Insurance Premiums ($ millions)

Line No.	Description	Approved 2023	Projected 2023	Forecast 2024
1	Insurance Premiums	$ 2.457	$ 2.507	$ 2.678

FBC's annual insurance renewal occurs in July of each year. The 2023 Projected insurance premium expense of $2.507 million is $0.050 million higher than 2023 Approved, as it incorporates the first six months of FBC's actual July 2023 to June 2024 insurance renewals. The 2024 Forecast is $2.678 million, which is an increase of $0.171 million from 2023 Projected. The 2024 Forecast is calculated based on the six months of actual insurance premiums from July 2023 to June 2024 of $1.234 million, plus a 5 percent increase for the remaining six months, and the cost of fire fighting services FBC pays to the Province of $0.148 million.[28]

6.3.3 BCUC Levies

FBC's 2024 Forecast for BCUC levies is $0.458 million. The 2024 Forecast is based on Order G-134-23 for the BCUC's Fiscal 2023/24 year, which represents the best information available at

[28] $2.468 million/2 = $1.234 million. $1.234 million x 1.05 = $1.295 million. $1.234 million + $1.295 million + $0.148 million annual firefighting service fee = $2.678 million.

this time, as the BCUC levy calculation for its Fiscal 2024/25 year will not be available until early or mid 2024.

BCUC levies receive flow-through treatment, with annual variances between actual and forecast amounts in O&M expense being recorded in the BCUC Levies Forecast Variance deferral account and amortized over one year.

6.3.4 Clean Growth Initiative – Electric Vehicle (EV) DCFC Stations

As discussed in Section 3.6, FBC's EV DCFC stations are prescribed undertakings under section 5 of the GGRR[29] and the cost of service associated with EV DCFC stations is subject to flow-through treatment. Please refer to Table 3-5 in Section 3.6 which provides a summary of the EV DCFC stations' costs and revenues from 2022 Actual to 2024 Forecast.

Table 6-7 below provides a breakdown of the 2023 Approved, 2023 Projected and 2024 Forecast O&M expenses for FBC's EV DCFC service. The O&M expenses consist of network management, repairs and maintenance, inspection fees, FBC internal labour, and the electricity costs from third-party utilities (i.e., for stations in Grand Forks, Nelson, and Penticton).

Table 6-7: Clean Growth Initiative – EV DCFC Stations ($ millions)

Line No.	Description	Approved 2023	Projected 2023	Forecast 2024
1	Network Management	$ 0.047	$ 0.037	$ 0.050
2	Repairs and Maintenance	0.009	0.040	0.050
3	Inspection Fees	0.067	0.042	0.096
4	FBC Labour Costs	0.070	0.030	0.070
5	Third Party Utilities Costs	0.026	0.032	0.044
6	Total	$ 0.219	$ 0.181	$ 0.310

As shown in Table 6-7 above, the 2023 Projected O&M expense for the EV DCFC service is $0.038 million lower than 2023 Approved. This is primarily due to reduced FBC labour costs as a result of a vacancy, and reduced inspection fees as the new inspection agreement did not commence until mid-2023. These decreases are partially offset by the increase in repairs and maintenance costs as well as the increase in third-party utilities costs. The 2023 Projected repairs and maintenance costs are higher than 2023 Approved because the 2023 Approved amount did not account for the regular maintenance costs for stations where the warranty period expired, whereas the 2023 Projected amount includes an estimate of the ongoing regular maintenance costs at stations that are no longer covered by the vendor's warranty period. With regard to the increase in third-party utilities costs, this is primarily due to increased utilization at the stations located in the service areas of third-party utilities (i.e., Grand Forks, Nelson, and Penticton) as well as the rate increases by the third-party utilities.

[29] Order G-215-21 dated July 14, 2021.

The 2024 Forecast is $0.129 million higher than 2023 Projected. This is primarily due to increased inspection fees due to the full year impact of the inspection agreement, and higher FBC labour costs as FBC expects to fill the vacancy for 2024. Other drivers of the increase are higher FLO Global Management Service fees for network management, as well as an increase in third-party utilities costs due to a combination of expected increases in utilization of stations located in the service areas of the third-party utilities and the estimated increase in the rates of the third-party utilities.

6.3.5 MRS Incremental Operating Expenses

In the Annual Review for 2022 Rates Decision,[30] FBC received approval of exogenous factor treatment for the incremental O&M and capital costs associated with MRS AR13. As explained in the Annual Review for 2022 Rates proceeding, FBC expected to incur one-time costs in 2021 and 2022 related to the adoption of the standards in AR13 as well as ongoing incremental O&M expenses commencing in 2023[31].

Table 6-8 below provides the 2023 Approved, 2023 Projected, and 2024 Forecast of incremental O&M related to MRS AR13.

Table 6-8: Incremental O&M for MRS AR13 ($ millions)

Line No.	Description	Approved 2023	Projected 2023	Forecast 2024
1	Labour	$ 0.490	$ 0.490	$ 0.490
2	Non-Labour	0.095	0.095	0.095
3	Total	$ 0.585	$ 0.585	$ 0.585

The 2023 Projected O&M is consistent with 2023 Approved. For 2024, FBC is forecasting the same level of spending as in 2023. The spending is related to the ongoing efforts to maintain procedures and processes, hardware and software that address supply chain risk assessments, ongoing licensing and maintenance of the hardware and software, and the documentation to maintain compliance of AR13. As noted in the Annual Review for 2022 Rates, FBC expects these costs to continue in future years.

6.4 NET O&M EXPENSE

Net O&M expense is gross O&M less capitalized overhead. As approved by the BCUC in Order G-166-20, the capitalized overhead rate is set at 15 percent for FBC, unchanged from 2023. After capitalized overhead, the net O&M expense is $63.174 million in 2024.

[30] Decision and Order G-374-21, p. 21.
[31] Exhibit B-2, Annual Review for 2022 Rates Application, Section 12.2.1, pp. 103-104; Exhibit B-3, BCUC IR1 24.2.

6.5 SUMMARY

Overall, the increase in gross O&M expense from 2023 Approved to 2024 Forecast is 2.3 percent. Formula-driven O&M is increasing at a rate of 3.6 percent while O&M forecast outside the formula is decreasing by approximately 36.2 percent from 2023 Approved.

The capitalized overhead rate for 2024 remains unchanged from 2023.

7. RATE BASE

7.1 INTRODUCTION AND OVERVIEW

FBC forecasts its Rate Base to be $1.714 billion for 2024. Rate Base is comprised of mid-year net plant in service, work in progress not attracting AFUDC, unamortized deferred charges, working capital, and the utility plant acquisition adjustment.[32]

FBC's 2024 Rate Base includes the full-year impacts of the 2023 closing projected plant balances as well as the impact of the following amounts:

- Mid-year impact of regular capital additions, net of CIAC additions, of $97.783 million;
- Mid-year impact of plant depreciation, net of CIAC amortization, of $66.744 million; and
- Capital additions of CPCNs and other Major Projects totalling $5.500 million, as discussed in Section 7.3 below, which include:
    - Full-year impact of $2.769 million for the final capital expenditures and related AFUDC in 2023 for the Kelowna Bulk Transformer Additions (KBTA) Project; and
    - Full-year impact of $2.731 million for the final capital expenditures and related AFUDC in 2023 for the Corra Linn Dam Spillway Gates Replacement Project.

In addition, various changes in deferred charges, working capital and other items increase rate base by a net amount of $2.735 million in 2024.

Details of the 2024 Forecast plant balances can be found in Section 11, Schedules 5 through 9.

7.2 REGULAR CAPITAL EXPENDITURES

As part of the MRP Decision and Order G-166-20, FBC received the following approvals for capital expenditures:

- Approval of FBC's forecasts submitted for regular capital expenditures (i.e., growth, sustainment, and other) for the years 2020 through 2022; and
- Approval of several items to be forecast on an annual basis.

Further, as part of FBC's 2023 Annual Review Decision and Order G-382-22, and Reconsideration Decision and Order G-87-23, FBC received approval of its forecasts of regular capital expenditures for the years 2023 and 2024.

The components of FBC's 2024 regular capital expenditures are shown in Table 7-1 below.

[32] The utility plant acquisition adjustment relates to the 1982 purchase of Plants 2, 3, and 4 and is being amortized over a period of 64 years.

Table 7-1: Regular Capital Expenditures ($ millions)

Line No.	Description	Approved 2023	Projected 2023	Forecast 2024	Reference
1	Forecast Capital	$ 92.440	$ 92.440	$ 93.433	Table 7-2, Line 4
2	Flow-Through Capital	0.248	0.580	0.500	Table 7-3, Line 2
3	Total Gross Regular Capital	$ 92.688	$ 93.020	$ 93.933	Sum of Lines 1 & 2
4	Less CIAC	(11.628)	(11.623)	(7.539)	Section 11, Schedule 9, Line 2
5	Net Regular Capital	$ 81.060	$ 81.397	$ 86.394	Sum of Lines 3 & 4

FBC notes that, pursuant to Order G-135-23, FBC is directed to file a CPCN application for the Fruitvale Substation Project prior to the start of construction. This project was included in the approved regular capital expenditure forecasts for 2023 and 2024. As the Fruitvale Substation Project now requires a CPCN, FBC has removed the capital expenditures from the 2023 Approved, 2023 Projected, and 2024 Forecast regular capital amounts shown in Tables 7-1 and 7-2 (forecast regular capital of $1.087 million in 2023 and $7.021 million in 2024). These expenditures will now be treated in the same manner as FBC's other CPCN and Major Project capital expenditures. Please refer to Section 7.3 for further detail.

In the subsections below, FBC provides further details on its regular capital expenditures for 2024.

7.2.1 Approved Capital Expenditures

The level of forecast capital expenditures approved for 2024 by Orders G-382-22[33] and G-87-23[34] is shown in Table 7-2 below. As discussed above, following Order G-135-23, FBC removed the 2023 Approved, 2023 Projected and 2024 Forecast sustainment capital expenditures related to the Fruitvale Substation Project; therefore, the amounts shown in Table 7-2 exclude the Fruitvale Substation Project expenditures.

Table 7-2: Approved Capital Expenditures ($ millions)

Line No.	Description	Approved 2023	Projected 2023	Forecast 2024	Reference
1	Growth Capital	$ 30.072	$ 30.072	$ 24.568	Section 11, Schedule 4, Line 2
2	Sustainment Capital	44.710	44.710	51.652	Section 11, Schedule 4, Line 3
3	Other Capital	17.658	17.658	17.213	Section 11, Schedule 4, Line 4
4	Total	$ 92.440	$ 92.440	$ 93.433	Section 11, Schedule 4, Line 5

[33] FBC Annual Review for 2023 Rates Decision and Order G-382-22.
[34] FBC Reconsideration Decision and Order G-87-23 regarding the FBC Application for Reconsideration and Variance of Decision and Order G-382-22.

7.2.2 Flow-Through Capital Expenditures

FBC is afforded flow-through treatment for certain capital items due to a variety of factors, including their uncontrollable nature, because they drive incremental revenues, because they are related to Clean Growth initiatives, or because of the uncertainty in scope, costs and timing.

The amounts for 2024 are shown in Table 7-3 below along with a comparison to 2023.

Table 7-3: Flow-Through Regular Capital Expenditures ($ millions)

Line No.	Description	Approved 2023	Projected 2023	Forecast 2024	Reference
1	Clean Growth Initiative - EV DCFC	0.248	0.580	0.500	
2	Total Forecast Capital Expenditures	$ 0.248	$ 0.580	$ 0.500	Section 11, Schedule 4, Line 8

7.2.2.1 EV DCFC Stations

As discussed in Section 3.6, FBC's EV DCFC stations are prescribed undertakings under section 5 of the GGRR[35], and the cost of service associated with EV charging stations is subject to flow-through treatment. Please refer to Table 3-5 of Section 3.6 which provides a summary of the EV DCFC stations' costs and revenues from 2022 Actual to 2024 Forecast.

Table 7-3 above shows the EV DCFC stations capital expenditures for 2023 Approved, 2023 Projected, and 2024 Forecast. The 2023 Projected EV DCFC stations capital expenditures are $0.332 million higher than 2023 Approved, primarily due to unbilled charges from 2022 construction activities, which are related to the planned DCFC stations in Keremeos and Princeton that were identified in FBC's Revised and Updated Application for EV DCFC Service and approved by Order G-215-21.[36] The construction was completed in 2022, but FBC did not receive all invoices for the work until 2023.

The 2024 Forecast capital expenditures are related to the accessibility improvement work at FBC's existing EV DCFC sites that was started in 2023. In 2023, FBC is projecting to complete the improvement work at four sites (which was included as part of the 2023 Approved expenditures), while the remaining sites are expected to complete in 2024. As noted in the Annual Review for 2023 Rates, the scope of the improvements include new or additional lighting, as the stations are available for use 24 hours a day, and paving for wheelchair access to the charger.

FBC is not forecasting the construction of any additional stations in 2024 at this time; however, FBC will continue to monitor the station utilization and customer demand to determine if additional stations are warranted.

[35] Order G-215-21 dated July 14, 2021.
[36] FBC's Revised and Updated EV DCFC Service Application, Table 2-2, pp. 10-11.

7.3 MAJOR PROJECTS CAPITAL EXPENDITURES

Major Projects are capital expenditures that do not form part of regular capital spending as they are approved through a separate CPCN or other application. As part of the MRP Decision,[37] the BCUC approved the continuation of the current process of reviewing Major Projects outside of the proposed MRP and approved the continuation of the existing financial threshold for CPCNs of $20 million for FBC for the MRP term.

For 2024, FBC is not forecasting any capital expenditures related to Major Projects. However, FBC's 2024 Forecast rate base includes the full-year impact of capital additions related to the KBTA Project and the Corra Linn Dam Spillway Gate Replacement Project. FBC also provides a brief discussion on the Fruitvale Substation Project, as FBC is expecting to submit a CPCN application for this project in 2023. Each of these projects is described further below.

KBTA Project

The KBTA project was approved by Order C-4-20 and involves the installation of a third terminal transformer at the F.A. Lee Terminal Station, including the reconfiguration of the 138 kV bus into an industry standard ring bus configuration. The project is expected to complete in 2023 with an estimated final cost of $23.287 million, inclusive of AFUDC and cost of removal. A total of $19.941 million (plus $0.577 million of removal costs) were included in FBC's rate base on January 1, 2023, with the remaining $2.769 million expected to enter FBC's rate base on January 1, 2024.

Corra Linn Dam Spillway Gates Replacement Project

The Corra Linn Dam Spillway Gates Replacement Project was approved by Order C-1-17 and involves the replacement of 14 spillway gates and upgrades to the associated infrastructure. As explained in FBC's Reconsideration Application to the Decision and Order G-382-22 for the Annual Review for 2023 Rates, which was approved by Order G-87-23, the replacement of all spillway gates was complete in 2022 and the costs were included in FBC's rate base between 2018 and 2023, with the remaining close-out activities delayed to 2023. The close-out activities, including lighting, outstanding claims, and clean-up, are estimated to be approximately $2.731 million and are expected to be complete in 2023; therefore, the costs are forecast to enter FBC's rate base on January 1, 2024. The final project cost is expected to be $80.835 million, inclusive of AFUDC and removal costs.

Fruitvale Substation Project

The Fruitvale Substation Project was included as part of FBC's regular capital forecasts for 2023 and 2024 in the Annual Review for 2023 Rates (forecast regular capital of $1.087 million in 2023 and $7.021 million in 2024). FBC's 2023 and 2024 regular capital forecasts were approved as part of the BCUC's Decision and Order G-382-22. However, following a complaint regarding the location of the proposed substation in Fruitvale, the BCUC issued Order G-135-23 on June 9, 2023, directing FBC to file an application for a CPCN related to the proposed Fruitvale Substation

[37] MRP Decision and Order G-166-20, pp. 132-133.

Project. As discussed in Section 7.2, FBC has removed the 2023 and 2024 capital expenditures related to the Fruitvale Substation Project from regular capital, as the expenditures will now be treated in the same manner as FBC's other CPCN and Major Project capital expenditures. FBC expects to file an application for a CPCN for the Fruitvale Substation Project before the end of 2023.

7.4 2024 PLANT ADDITIONS

The 2024 Plant Additions are comprised of: (i) FBC's 2024 regular capital expenditures from Section 7.2; (ii) the Major Projects from Section 7.3 to the extent that portions of those projects are placed into service; (iii) the change in work in progress which adjusts for capital expenditures for projects that are in progress at year-end; (iv) AFUDC; and (v) overhead capitalized for the year. A reconciliation of capital expenditures to plant additions is shown below and is also provided in Section 11, Schedule 5.

Table 7-4: Reconciliation of 2024 Capital Expenditures to Plant Additions ($ millions)[38]

Line No.	Description		Forecast 2024	Reference
1	Forecast Capital Expenditures	$	93.433	Section 11, Schedule 5, Line 2
2	Flow-Through Capital Expenditures		0.500	Section 11, Schedule 5, Line 3
3	Total Gross Regular Capital Expenditures		93.933	Sum of Lines 1 and 2
4				
5	Capitalized Overhead		11.148	Section 11, Schedule 5, Line 16
6	AFUDC		0.241	Section 11, Schedule 5, Line 17
7	Change in Work in Progress		-	Section 11, Schedule 5, Line 19
8	Total Regular Additions to Plant		**105.322**	Sum of Lines 3 through 7
9				
10	Special Projects and CPCN			
11	Capital Expenditures		-	Section 11, Schedule 5, Line 22
12	AFUDC		0.001	Section 11, Schedule 5, Line 23
13	Change in Work in Progress		5.499	Section 11, Schedule 5, Line 25
14	Total Special Projects and CPCN Additions to Plant		**5.500**	Sum of Lines 11 through 13
15				
16	Total Plant Additions	**$**	**110.822**	Line 8 + Line 14

7.5 ACCUMULATED DEPRECIATION

Rate base includes both the accumulated depreciation on plant in service and accumulated amortization of CIAC. Both are increased through depreciation expense and decreased through retirements.

[38] Line 11 of Table 7-4 is zero because, as described in Section 7.3, there are no capital expenditures forecast in 2024 for the two approved CPCN Projects (i.e., the KBTA Project and the Corra Linn Dam Spillway Gates Replacement Project). Further, FBC will be filing for a CPCN related to the Fruitvale Substation Project in 2023, as such, FBC has not included the forecast capital expenditures related to this project.

The depreciation rates used for 2024, which were approved by Order G-166-20 and are based on FBC's most recent depreciation study, include the recovery of the estimated future costs of removal over the average service life of the assets (net salvage) in accumulated depreciation. Depreciation is calculated beginning January 1 of the year after the assets are placed in service, which is the treatment approved by Order G-139-14.

Based on calculating depreciation expense at these approved depreciation rates on the opening plant-in-service balance, the 2024 depreciation expense is calculated as $66.744 million.[39]

7.6 DEFERRED CHARGES

On May 3, 2017, the BCUC issued its Regulatory Account Filing Checklist.[40] The stated purpose of the checklist is to assist regulated entities when filing regulatory account requests and to facilitate an efficient review by the BCUC.

The checklist classifies deferral accounts as one of: (a) forecast variance account; (b) rate smoothing account; (c) benefit matching (capital-like) account; (d) retroactive expense account; or (e) other. In Section 11, Schedule 11, FBC has classified its rate base deferral accounts in accordance with this classification.

The 2024 Forecast mid-year balance of unamortized deferred charges in rate base for FBC is a debit of $51.287 million.

The 2024 debit balance is driven largely by the balance in the Demand Side Management (DSM) deferral account of $44.063 million.

Figure 7-1 provides the mid-year deferral account balances summarized by deferral account category.

[39] $72.053 million depreciation expense as shown in Section 11, Schedule 21, Line 2 less $5.309 million amortization of CIAC as shown in Section 11, Schedule 21, Line 8.
[40] BCUC Letter, Log No. 53608, Appendix B.

Figure 7-1: FBC Forecast Mid-Year Balances of Rate Base Deferral Accounts by Category

Based on the approved amortization and the opening balances of each deferral account, the amortization expense, including both rate base and non-rate base deferral accounts, is calculated to be a credit of $2.860 million,[41] which will be returned to customers through the proposed 2024 rates. The subsections below include a discussion on new rate base deferral accounts and changes or updates to existing rate base deferral accounts. For a discussion on non-rate base deferral accounts, please refer to Section 12.

7.6.1 New Deferral Accounts

FBC is seeking approval to create five new rate base deferral accounts in this Application:

- 2025 Multi-year Rate Plan (MRP) Application;
- 2024 Mandatory Reliability Standards Audit;
- PST Rebate on Select Machinery and Equipment;
- BC Cost of Living Credit; and
- Climate Change Operational Adaptation (CCOA) Plan.

Table 7-5 below addresses the considerations identified in the Regulatory Account Filing Checklist as they pertain to each deferral accounts requested. For a detailed description of each deferral account, please refer to Sections 7.6.1.1 to 7.6.1.5 below.

[41] Section 11, Schedule 21, Column 3, Sum of Lines 5 and 6.

Table 7-5: Deferral Account Filing Considerations

Item	Consideration	2025 MRP Application	2024 MRS Audit	PST Rebate on Select Machinery and Equipment	BC Cost of Living Credit	Climate Change Operational Adaptation Plan
I.	Indicate if the request is: (a) for a modification or a change in scope to an existing Commission approved regulatory account; or (b) to establish a new regulatory account.	The 2025 MRP Application is a new deferral account. Please refer to Section 7.6.1.1 for additional information.	The 2024 MRS Audit is a new deferral account. Please refer to Section 7.6.1.2 for additional information.	The PST Rebate on Select Machinery and Equipment is a new deferral account. Please refer to Section 7.6.1.3 for additional information.	The BC Hydro Cost of Living Credit is a new deferral account. Please refer to Section 7.6.1.4 for additional information.	The Climate Change Operation Adaptation Plan is a new deferral account. Please refer to Section 7.6.1.5 for additional information.
a)	If the request is for a modification or change in scope to an existing regulatory account, explain why the existing regulatory account is an appropriate account to use (specifically addressing the existing account's intended and approved purpose, mechanism for recovery, timeline for recovery and carrying costs).	N/A	N/A	N/A	N/A	N/A

Item	Consideration	2025 MRP Application	2024 MRS Audit	PST Rebate on Select Machinery and Equipment	BC Cost of Living Credit	Climate Change Operational Adaptation Plan
b)	If the request is for approval of a new regulatory account, state the purpose of the regulatory account and explain its intended use.	The requested account is a regulatory proceeding cost account, which is routinely sought by utilities to capture external costs related to the preparation, filing, and regulatory review of applications.	The requested account will capture periodic incremental costs of the MRS compliance audit.	The requested account will capture PST Rebates on Select Machinery and Equipment received from the Province of BC.	The requested account will capture the residual balance of the BC Cost of Living Credit.	The requested account will capture costs related to the development of the Climate Change Operational Adaptation Plan.
II.	Propose a term (i.e., length of time) that the regulatory account should be approved for and explain why that term is appropriate.	The term of the account encompasses the preparation and filing of the relevant regulatory application and its review by the BCUC.	The term of the account encompasses the required time to conduct the audit.	The term of the account encompasses the required time for the Province of BC to approve the qualified claim filed by FBC and issue the refund payment.	The term of the account encompasses the time required to distribute the credits to all applicable customers.	The term of the account encompasses the time required for the development of the CCOA Plan and subsequent business cases as discussed in the 2021 Long Term Electric Resource Plan (LTERP).
III.	Identify any alternate treatments that were considered, including an overview of what the accounting treatment would be in the absence of approval of the request to establish a regulatory account, and explain why these alternate treatments may not be appropriate.	In the absence of deferral accounts for regulatory proceedings, the costs of regulatory proceedings would have to be forecast as an O&M expense (outside of the MRP index-based O&M as regulatory proceeding costs are not included in Base O&M Expense) and trued up annually by way of the	In the absence of a deferral account, the audit costs would have to be forecast as an O&M expense (outside of the MRP index-based O&M, as the costs are not included in Base O&M Expense) and trued up annually by way of the Flow-Through deferral account. FBC considers this to be a more cumbersome	In the absence of a deferral account, the rebate would be recorded as an offset in the applicable accounts where the original PST costs were recorded, whether those accounts were O&M or capital. FBC considers this to be a less transparent way of recording the rebates as it is the cost-of-	In the absence of a deferral account, the credit would remain in an FBC liability account until the residual balance is distributed through inquiries. FBC does not expect there will be enough inquiries to distribute the total residual balance. Eventually, the residual balance would be recorded as	In the absence of a deferral account, the costs would have to be forecast as an O&M expense (outside of the MRP index-based O&M, as the costs are not included in Base O&M Expense) and trued up annually by way of the Flow-Through deferral account. FBC considers this to be a more cumbersome

Item	Consideration	2025 MRP Application	2024 MRS Audit	PST Rebate on Select Machinery and Equipment	BC Cost of Living Credit	Climate Change Operational Adaptation Plan
		Flow-Through deferral account. FBC considers this to be a more cumbersome and less efficient means of accounting for regulatory proceeding costs. It is accepted regulatory practice to defer the costs of regulatory applications for review and recovery following the regulatory review of the application itself. Review and recovery after the completion of the regulatory process allows for more transparency as the history of the costs is simpler to track and report.	and less efficient means of managing the audit costs. In addition, the use of a deferral account permits multi-year cost recovery, which is consistent with the three-year period between audits, as opposed to recovery in a single year.	service impacts of the amounts credited to capital that would be returned to customers over a longer timeframe, rather than the rebate amount itself over one year as proposed using the deferral account approach.	income, and FBC would need to request a method of returning that income to customers, either via the Flow-Through deferral or by including the amount in its revenue requirements. The use of a deferral account permits the remaining credits to be used to benefit all customers, in a timely and efficient manner, consistent with the purpose of the credit.	and less efficient means of managing these costs.

Item	Consideration	2025 MRP Application	2024 MRS Audit	PST Rebate on Select Machinery and Equipment	BC Cost of Living Credit	Climate Change Operational Adaptation Plan
IV a)	Address: whether, or to what extent, the item is outside of management's control;	Regulatory proceeding cost accounts are necessary because the number and type of regulatory proceedings can vary significantly by year. Further, once a regulatory proceeding is identified, the costs of that proceeding cannot be accurately forecast by the utility given that they can vary substantially, are not known at the time of making the regulatory account request, are unique to the circumstances for each application, may change as the regulatory review process unfolds, and are dependent on factors not within the utility's control. Factors not within the control of the utility include the regulatory process determined by the BCUC and the degree of involvement of interveners.	Compliance audits of MRS are conducted every three years. The scope and complexity of audits varies depending on the standards under review and are not within the control of the Company.	The final amount of PST rebates claimed by FBC are subject to approval by the Province of BC.	The amount of credit available to FBC and the eligibility criteria was determined by the Province of BC.	As a result of the ongoing impacts of global climate change, FBC has determined it is imperative to address the risks of climate change risk on its system. Therefore, although direct costs are within Management's control, the need to incur these costs is considered necessary.

Item	Consideration	2025 MRP Application	2024 MRS Audit	PST Rebate on Select Machinery and Equipment	BC Cost of Living Credit	Climate Change Operational Adaptation Plan
b)	the degree of forecast uncertainty associated with the item;	Refer to IV. a). FBC forecasts additions to the deferral account based on the expected type of review process and degree of intervener involvement. Actual costs are recorded in the account so that actual, not forecast, costs are recovered in rates.	Refer to IV. a). FBC forecasts additions to the deferral account based on past audit experience. Actual costs are recorded in the account so that actual, not forecast, costs are recovered in rates.	Refer to IV. a). FBC forecasts additions to the deferral account based on the rebates received to date plus those claimed and expected to be received. Actual expected rebates will be recorded in the account so that actual, not forecast, rebates are returned in rates.	Refer to IV. a). FBC forecasts additions to the deferral account based on the residual balance of credits remaining to date. The actual residual balance, inclusive of further eligible inquiries, will be recorded in the account so that the actual, not forecast, remaining credits are returned in rates.	Refer to IV. a). FBC forecasts additions to the deferral account based on expected incremental resources required to complete the plan. Actual costs are recorded in the account so that actual, not forecast, costs are recovered in rates.
c)	the materiality of the costs	The number and size of regulatory proceedings vary from year to year, and represent costs not included in Base O&M for the purpose of determining formula O&M Expense under the MRP. Please refer to Section 7.6.1.1 for additional information.	Audit preparation and participation impacts many individuals and business units and is not manageable within FBC's formula O&M Expense. FBC expects costs related to the MRS Audit of approximately $0.375 million ($0.274 million after-tax). Please refer to Section 7.6.1.2 for additional information.	FBC expects rebates of approximately $0.591 million ($0.431 million after-tax). Please refer to Section 7.6.1.3 for additional information.	FBC expects the remaining credit to be approximately $0.507 million ($0.370 million after-tax). Please refer to Section 7.6.1.4 for additional information.	FBC expects costs related to the CCOA Plan of approximately $0.225 million ($0.164 million after tax) in 2023 and a further $0.192 million ($0.140 million after-tax) in 2024. Please refer to Section 7.6.1.5 for additional information.

Item	Consideration	2025 MRP Application	2024 MRS Audit	PST Rebate on Select Machinery and Equipment	BC Cost of Living Credit	Climate Change Operational Adaptation Plan
d)	any impact on intergenerational equity	Generally, FBC recovers the costs of regulatory proceedings over the period of time related to the application, which serves to match the costs and benefits. There are no intergenerational inequities inherent in this practice.	FBC expects to recover the audit costs over the period of time between audits, which serves to match the costs and benefits. There are no intergenerational inequities inherent in this practice.	FBC expects to return the rebates over the same period of time as the qualifying period to make the PST rebate claims. There are no intergenerational inequities in this practice.	FBC expects to return the remaining credit over the same period of time as the credit is made available by the Province of BC. There are no intergenerational inequities in this practice.	FBC expects to recover the costs of the CCOA Plan over the period of time required to develop the plan and subsequent business cases as outlined in the 2021 LTERP. There are no intergenerational inequities inherent in this practice.
V.	Classify the regulatory account as either: (a) forecast variance account; (b) rate smoothing account; (c) benefit matching account; (d) retroactive expense account; or (e) other.	FBC generally classifies regulatory proceeding accounts as benefit matching accounts since the costs are recovered over the period of time related to the applications, which serves to match the costs and benefits of the application.	The account is classified as a benefit matching account since the costs will be recovered over the period of time between audits, which serves to match the costs and benefits of the audit.	The account is classified as “other”.	The account is classified as “other”.	The account is classified as “other”.
VI.	Identify if the regulatory account is a cash or non-cash account.	Regulatory proceeding cost accounts are cash accounts.	The MRS Audit deferral account is a cash account.	The PST Rebate on Select Machinery and Equipment is a cash account.	The BC Cost of Living Credit deferral account is a cash account.	The Climate Change Operational Adaptation Plan deferral account is a cash account.

Item	Consideration	2025 MRP Application	2024 MRS Audit	PST Rebate on Select Machinery and Equipment	BC Cost of Living Credit	Climate Change Operational Adaptation Plan
VII.	Specify what additions to the regulatory account are being requested (i.e. type and amount of additions), including whether the account is intended to capture additions for a specific period of time or on an ongoing basis.	Eligible costs include the BCUC's direct costs, notice publication costs, fees for consultants or experts, external legal counsel fees, courier and miscellaneous administrative costs, and participant assistance cost awards incurred in the preparation, filing and regulatory review of the applications. Regular labour and staff expenses related to regulatory applications are included in formula O&M Expense.	Eligible costs are incremental to ongoing MRS expenses and include labour, consulting and miscellaneous expenses not included in formula O&M Expense.	PST Rebates received from the Province of BC for claims filed by FBC for the qualifying period. Please refer to Section 7.6.1.3 for additional information.	The remaining credit is the total funds received by FBC less any credit already applied to customer bills as of June 2023. FBC will continue to capture any credits provided to customers from eligible inquiries for the credit. Please refer to Section 7.6.1.4 for additional information.	Eligible costs include fees for consultants required for the development of the plan.
VIII.	Propose a mechanism for recovery (e.g. how the balance in the regulatory account will be recovered or refunded to ratepayers) and explain why it is appropriate.	Costs are recovered in revenue requirements by way of amortization expense.	Costs are recovered in revenue requirements by way of amortization expense.	Rebates will be refunded in revenue requirements by way of amortization expense.	Credits will be refunded in revenue requirements by way of amortization expense.	Costs are recovered in revenue requirements by way of amortization expense.

Item	Consideration	2025 MRP Application	2024 MRS Audit	PST Rebate on Select Machinery and Equipment	BC Cost of Living Credit	Climate Change Operational Adaptation Plan
IX.	Propose a timeline for recovery (e.g. the period over which the regulatory account balance is either collected or refunded; also referred to as the amortization period) and explain why it is appropriate.	Generally, FBC proposes to amortize the costs of regulatory proceedings over the period of time related to the application, which serves to match the timing of costs and benefits. Please refer to Sections 7.6.1.1 for additional information.	FBC proposes to amortize the costs over three years beginning January 1, 2024, to reflect the period until the next audit. Recovery of the costs over the period of time between audits serves to match the costs and benefits of the audit. Please refer to Section 7.6.1.2 for additional information.	FBC proposes to refund the rebates over one year beginning January 1, 2024, to match the approximate qualifying period of eligible PST paid on purchases. Please refer to Section 7.6.1.3 for additional information.	FBC proposes to refund the remaining credits over one year beginning January 1, 2024. Please refer to Section 7.6.1.4 for additional information.	FBC proposes to amortize the costs over four years beginning January 1, 2024 to reflect the CCOA Plan timeline discussed in the 2021 LTERP. Please refer to Section 7.6.1.5 for additional information.
X.	Propose a carrying cost for the balance in the regulatory account and explain why it is appropriate.	Rate base deferral accounts are included in rate base and therefore, implicitly financed using the weighted average cost of capital (WACC).	Rate base deferral accounts are included in rate base and therefore implicitly financed using the weighted average cost of capital (WACC).	Rate base deferral accounts are included in rate base and therefore implicitly financed using the weighted average cost of capital (WACC).	Rate base deferral accounts are included in rate base and therefore implicitly financed using the weighted average cost of capital (WACC).	Rate base deferral accounts are included in rate base and therefore implicitly financed using the weighted average cost of capital (WACC).
XI.	Outline a recommended regulatory process for the Commission's review of the application.	The proposed deferral account can be reviewed as part of the present proceeding. Deferral account approvals and disposition are generally determined in revenue requirement proceedings.				

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7.6.1.1 2025 Multi-Year Rate Plan (MRP) Application

FBC's current Multi-year Rate Plan (MRP) approved by Order G-166-20 will end in 2024. FBC has started developing its next rate plan and expects to file this rate plan with the BCUC in early 2024. FBC will incur regulatory costs related to the development of the application and is requesting approval to establish a rate base deferral account to capture these costs, which will include BCUC costs, participant funding costs, external legal fees, expert/consulting costs, notice publication costs, and miscellaneous facilities, stationery, and supplies costs. FBC forecasts costs of $0.350 million ($0.256 million after-tax) in 2023 and $1.200 million ($0.876 million after-tax) in 2024. Actual costs will vary depending on how the application progresses and will be confirmed after the regulatory process is completed.

FBC is only requesting approval to establish this deferral account. FBC will propose an amortization period for the deferral account in a future rate-setting application (i.e., subsequent to the completion of the 2025 MRP application proceeding).

7.6.1.2 2024 Mandatory Reliability Standards (MRS) Audit

FBC's triennial MRS compliance audit is scheduled to occur in 2024. This audit will be performed by the administrator of the BC MRS Program, the Western Electricity Coordinating Council (WECC), and will include a review, at minimum, of all applicable reliability standards identified in the Actively Monitored List. This will include Critical Infrastructure Protection (CIP) and Operations and Planning (O&P) standards. Eligible costs are incremental labour and expenses directly caused by the periodic audit and therefore not included in Formula O&M Expense. Based on previous audits, FBC forecasts costs of $0.375 million before tax ($0.274 after tax) in 2024.

FBC is requesting approval to establish a rate base deferral account to capture the costs related to the 2024 MRS Audit. Further, FBC is proposing to amortize these costs over three years beginning January 1, 2024. This amortization period is appropriate as it reflects the period until the next MRS triennial audit.

7.6.1.3 PST Rebate on Select Machinery and Equipment

The BC PST Rebate on Select Machinery and Equipment is a provincial government program to help corporations recover from the financial impacts of the COVID-19 pandemic. Eligible businesses can receive as a rebate the PST paid on purchases of specified equipment and software during the qualifying period between September 17, 2020 and March 31, 2022.

FBC is eligible to claim a BC PST Rebate on Select Machinery and Equipment on capital purchases of software and equipment and has filed for these rebates for the qualifying periods as set out by the Province of BC. To date, FBC has received $0.029 million ($0.021 million after-tax) in rebates and expects additional rebates of approximately $0.562 million ($0.410 million after-tax) to be received by December 31, 2023.

FBC is requesting approval to establish a rate base deferral account to capture the PST Rebates on Select Machinery and Equipment received from the Province of BC. Further, FBC is proposing to amortize these rebates to customers over one year beginning January 1, 2024, to match the approximate qualifying period of eligible PST paid on purchases.

7.6.1.4 BC Cost of Living Credit

On November 18, 2022, the Province of BC issued OIC 571/2022[42] for a one-time cost-of-living credit to all eligible residential and commercial electricity customers through a BC Hydro bill credit, including those who receive their electricity service from FBC or a municipal utility.

FBC received funds through BC Hydro for applying the credits to all eligible residential electricity customers in the amount of a one-time $100 cost-of-living credit and to all eligible commercial electricity customers as a one-time bill credit calculated based on their prior year electricity consumption.

FBC received a total of $23.816 million and applied $23.290 million of credits to all eligible customers as of March 10, 2023. In addition to the bill credits applied to eligible customers, FBC has committed to provide credits to customers if/when a customer inquires about such credits to FBC (and if the customer is determined to be eligible)[43]. Between March 10, 2023 and May 31, 2023, FBC received a total of six inquiries (three residential and three commercial customers), resulting in a further $0.019 million of credits applied. The total credits applied to eligible customers as of June 10, 2023 are therefore $23.309 million, with $0.507 million ($0.370 million after-tax) of residual credits which FBC proposes to include as a credit amortization (i.e., return to all customers) in 2024 rates.

FBC requested and received confirmation from the Ministry of Energy, Mines and Low Carbon Innovation (EMLI) that there is no expectation or requirement for FBC to return the residual credits to either BC Hydro or the Province of BC. Furthermore, EMLI agreed that the remaining funds could be used to benefit all FBC customers through rates, which is consistent with the purpose of the bill credits. As such, FBC is requesting approval in this Application to establish a rate base deferral account to capture the residual balance of the BC Cost of Living Credit and to amortize the residual credits to customers through rates over a one-year period beginning January 1, 2024.

As agreed with EMLI, FBC will continue to field inquiries from customers and will provide bill credits to customers that are determined to be eligible. As noted above, FBC only received a total of six inquiries from March to May 2023 and has received no inquiries since then. As such, FBC is expecting a very limited number of inquiries to occur in the remaining months of 2023 and into 2024. However, should any further bill credits be issued to eligible customers in 2023 or 2024, FBC will record these issued amounts in the deferral account. If there is any remaining balance

[42] https://www.bclaws.gov.bc.ca/civix/document/id/oic/oic_cur/0571_2022.

[43] OIC 571/2022 sets out the eligibility criteria which defined that customers must be a customer and receiving service on October 1, 2022. Due to the timing lapse between October 1, 2022 and when the credits are distributed starting from December 2022 to March 2023 (the credit was announced by the Province of BC on November 18, 2022), customers could be connecting to and/or leaving FBC's system, potentially resulting in eligible customers not receiving the bill credit. As such, FBC agreed to field inquiries and continue to pay out any eligible credits.

(credit or debit) at the end of 2024, FBC will amortize the remaining balance into rates in the subsequent year (i.e., 2025).

7.6.1.5 Climate Change Operational Adaptation (CCOA) Plan

As discussed in FBC's most recent Long Term Electric Resource Plan (2021 LTERP) accepted by Order G-380-22, the threat that climate change presents to FBC infrastructure and operations is a continuing reality that FBC is taking seriously; accordingly, FBC is developing a roadmap for climate change adaptation.[44] FBC's Climate Change Operational Adaptation (CCOA) Plan focuses on addressing the climate change risks associated with five hazards: wildfires, flooding, extreme temperatures, snowstorms, and windstorms. During the initial phase of the CCOA Plan, FBC is working with consultants to identify assets vulnerable to each hazard, define the current and future risk profiles of the vulnerable assets due to these hazards, and propose adaptation strategies. These strategies may consist of, but are not limited to, system hardening, asset replacement, or modification of design standards. Future phases will apply these results and strategies to existing assets to determine whether risk reduction projects will be required.

FBC is requesting approval to establish a rate base deferral account to capture the costs related to the CCOA Plan. FBC forecasts costs of $0.225 million ($0.164 million after-tax) in 2023 and a further $0.192 million ($0.140 million after-tax) in 2024. The costs are primarily related to the resources required to develop the roadmap for climate change adaptation and, stemming from the roadmap, develop the business cases for the five key hazard areas (i.e., wildfires, flooding, extreme temperatures, snowstorms and windstorms). FBC is proposing to amortize these costs over four years beginning January 1, 2024. This period aligns with the CCOA Plan timeline discussed in the 2021 LTERP, which states that the development of the CCOA Plan and subsequent business cases would occur between now and 2027. FBC will continue to provide updates on the progress of the CCOA Plan and the deferral account in future annual reviews or revenue requirement applications.

7.6.2 Existing Deferral Accounts

In the discussion below, FBC provides information on one existing deferral account.

7.6.2.1 Princeton Office Disposition Deferral Account

On January 24, 2023, pursuant to Order G-14-23, FBC was approved to sell the Princeton Office Properties, consisting of the land and buildings located on Bridge Street in Princeton, BC, to the Town of Princeton. FBC was also approved to establish the Princeton Office Disposition non-rate base deferral account to capture the net gain on the sale, and to transfer the balance in the non-rate base deferral account to a rate base deferral account on January 1, 2024 and commence amortization of the deferral account over one year in 2024. FBC was directed to provide details

[44] FBC 2021 LTERP Application, p. 140; Exhibit B-2, BCUC IR1 24.4.

on the final balance in the Princeton Office Disposition deferral account in the Annual Review for 2024 Rates.

FBC received written notification of the removal of the Buyer's Subject Conditions on February 10, 2023, and on March 13, 2023, the sale of the Princeton Office Properties was fully completed. The final projected ending balance of the deferral account (i.e., projected to the end of 2023) is approximately $0.406 million, and this credit amount has been included in the 2024 revenue requirements and rates.

Please refer to Table 7-6 below for a breakdown of the net gain on the sale of the Princeton Office Properties. FBC notes that the estimated net gain on sale at the time of filing the Princeton Office Properties Application was $0.346 million. The difference between the original estimate and the final projected ending balance is solely due to a difference in the net book value of the land and building. When preparing this Application, FBC discovered that it incorrectly calculated the accumulated depreciation on the building at the time of filing the Princeton Office Properties Application. FBC has now corrected this error and, as a result, the net gain on sale to be provided to customers is higher than originally forecast in the Princeton Office Properties Application.

Table 7-6: Breakdown of Final Net Gain on Sale of the Princeton Office Properties

		$ millions
Sales Proceeds		0.474
Less:	Net Book Value of Land and Building	(0.041)
	Disposal Costs	(0.019)
	Taxes Payable	(0.008)
Gain on Sale		**0.406**

7.7 WORKING CAPITAL

The working capital component of rate base is comprised of cash working capital and other working capital.

Cash working capital is defined as the average amount of capital provided by investors in the Company to bridge the gap between the time expenditures are required to provide service (expense lag) and the time collections are received for that service (revenue lag). The cash working capital requirements that have been included reflect the most recent Lead Lag Study results, as approved through Order G-166-20.

Other working capital includes customer (DSM) loans, employee loans and withholdings, and inventory of materials and supplies. 2024 amounts are forecast based on 2022 Actual levels.

7.8 SUMMARY

FBC's rate base includes the impact of regular and Major Project capital expenditures, adjusted for work-in-progress, AFUDC and overheads capitalized. FBC has provided forecasts for all of its

rate base deferral accounts in the financial schedules included in Section 11. In Section 7.6.1, FBC requested approval of five new deferral accounts; and in Section 7.6.2, FBC discussed one existing deferral account. Finally, the rate base includes cash and other working capital.

8. FINANCING AND RETURN ON EQUITY

8.1 INTRODUCTION AND OVERVIEW

FBC has prepared this Application using a capital structure of 60 percent debt and 40 percent equity and a Return on Equity (ROE) of 9.15 percent, as approved by Orders G-129-16 and G-47-14. FBC's ROE is set at a premium of 40 basis points over the benchmark ROE, which is the ROE approved for FEI. FBC is currently awaiting a decision on Stage 1 of the BCUC-initiated Generic Cost of Capital (GCOC) proceeding which it expects to be issued in the upcoming months. FBC will provide an update to its rate calculations as part of an Evidentiary Update subsequent to the GCOC decision being issued.

The 2024 Forecast for financing costs, including the interest expense on issued long- and short-term debt and on new issuances that are forecast, has been updated as described in Section 8.3 below. Based on the updated financing costs, FBC's AFUDC rate for 2024 (which is equal to its after-tax weighted average cost of capital) is 5.75 percent.[45] Any variances from interest rates used to set rates, and any variances in interest resulting from items subject to flow-through in the Flow-through deferral account, will be flowed through to customers. All other differences in interest expense will affect the achieved ROE and be subject to earnings sharing.

8.2 CAPITAL STRUCTURE AND RETURN ON EQUITY

The Company finances its investment in rate base assets with a mix of debt and equity, as approved by the BCUC from time to time. Pursuant to Order G-47-14, FBC used the currently approved capital structure of 60.0 percent debt and 40.0 percent equity, with an equity risk premium of 40 basis point over the benchmark ROE, which was set at 8.75 percent by Order G-129-16, effective January 1, 2016, to calculate rates in this Application.

8.3 FINANCING COSTS

Debt financing costs include the borrowing costs on issued debt as well as on new issuances that are forecast. Debt consists of both long- and short-term debt.

8.3.1 Long-Term Debt

FBC is both a private and public issuer of long-term debt. FBC plans to issue additional long-term debt of approximately $100 million in April 2024 and will use the funds to repay existing indebtedness and finance the Company's capital expenditure program. The 2024 debt issuance is reflected in the financial schedules at a rate of 4.90 percent.[46] The exact timing, amount and rate of the 2024 issuance will depend on future market conditions and capital expenditure

[45] As part of the Evidentiary Update, FBC will update the AFUDC rate for 2024 to reflect any changes resulting from the GCOC decision.
[46] Section 11, Schedule 27, Line 9.

requirements. Variances in interest expense related to the timing and amount of the issuances of the debt or the rates at which they are issued will be captured in the Flow-through deferral account.

8.3.2 Short-Term Debt

FBC obtains short-term funding primarily through the issuance of commercial paper to Canadian institutional investors. FBC backstops the commercial paper issuances by maintaining a $150 million committed credit facility that matures in April 2027.[47] This facility is also used to issue letters of credit. The credit facility, along with a $10 million overdraft facility, provides FBC with short-term liquidity to fund its capital program and working capital requirements.

8.3.3 Forecast of Interest Rates

FBC uses interest rate forecasts to estimate future interest expense. Forecasts of Treasury Bills and benchmark Government of Canada Bond interest rates are used in determining the overall interest rates for short-term debt and for rates on new issues of long-term debt, respectively. The forecasts are based on available projections made by Canadian Chartered banks.

Credit spreads on new long-term debt are based on current indicative rates, on the assumption that the current credit ratings of FBC are maintained.

FBC's short-term borrowing rate is based on the rate at which it issues commercial paper. Since commercial paper issuance rates are not forecast by economists, a forecast needs to be derived by FBC. The forecast is based on the historical differential between the Canadian Deposit Overnight Rate (CDOR) and the rate obtained by FBC under its commercial paper program. CDOR is used because FBC's short-term borrowings under its credit facility are priced based on CDOR and therefore CDOR is tracked relative to FBC's commercial paper borrowings. As CDOR is not forecast by economists, FBC must first obtain the 3-Month T-Bill rate forecast and then convert it to a CDOR forecast. FBC does this by taking the 3-year historical spread between CDOR and the 3-month T-Bill rate. Then, to derive the short-term borrowing rate forecast, FBC adjusts the CDOR forecast with the historical spread between CDOR and rates of issuances under its commercial paper program.

The 3-month T-Bill forecast for 2024 is 4.27 percent, which is an increase from the 3.14 percent approved in 2023. FBC continues to face a rising interest rate environment due to high inflation and the Bank of Canada continuing to raise its policy interest rate in an attempt to slow economic growth and reduce core inflation. While the inflation in Canada eased to 3.40 percent in May 2023 from a high of 8.10 percent from a year ago, the downward movement was driven largely by lower energy prices rather than easing underlying inflation. The Bank of Canada's latest interest rate

[47] On July 14, 2023, FBC filed an application with the BCUC to increase the principal amount of the credit facility from $150 million to $200 million and to extend the maturity date of the credit facility to April 2028. If this application is approved, FBC will include any related impacts in the Evidentiary Update which FBC expects to file subsequent to the GCOC decision being issued.

increase in July 2023 brings the overnight rate to 5.0 percent, which was the tenth interest rate increase since March 2022 when the overnight rate was at 0.25 percent.

For 2024, FBC forecasts higher Other Financing Fees than the 2023 Approved amount due to higher customer deposit interest, resulting from a higher prime rate in 2023. Other Financing Fees include the fees that FBC incurs for its letters of credit under the credit facility, as well as interest paid on customer deposits. The short-term borrowing rate forecast is shown in Table 8-1 below.

Table 8-1: Short Term Interest Rate Forecast

FBC Short Term Interest Rate	Approved 2023	Projected 2023	Forecasted 2024
3-Month T-Bill Rate [1]	3.14%	5.04%	4.27%
Spread to CDOR	0.36%	0.41%	0.41%
CDOR Rate	3.50%	5.45%	4.69%
Spread to CP	-0.36%	-0.47%	-0.47%
CP Dealer Commission	0.10%	0.10%	0.10%
ST Interest Rate on Credit Facilities	**3.24%**	**5.09%**	**4.32%**
Fixed Financing Fees [2]			
Standby fee on Undrawn Credit [3]	0.44%	0.24%	0.32%
Renewal Fee on Undrawn Credit	0.12%	0.07%	0.09%
Other Financing Fees	0.44%	0.34%	0.49%
ST Interest Rate on Fixed Financing Fee	**1.00%**	**0.64%**	**0.89%**
FBC Short Term Rate	**4.24%**	**5.73%**	**5.21%**

Notes to Table:

[1] 3-month T-Bill rate for 2024 is a weighted average rate based on forecasts provided by Canadian Chartered banks in July 2023.

[2] Fixed financing fees represent the costs of maintaining the credit facility and letter of credit facility, which are fixed fees incurred regardless of whether FBC draws from the credit facility. The fees have been converted into a short-term rate for forecast purposes.

[3] A standby fee of 20 bps is charged on undrawn credit facility amounts, which would change if credit facility amounts are drawn through banker acceptances or prime loans. However, the forecast assumes FBC will borrow through commercial paper and will not change the undrawn credit facility fee percentage.

4. Other financing fees include commercial paper issuance fees, letter of credit fees, customer deposit interest expense and miscellaneous bank administration costs. The letter of credit fees, customer deposit interest and miscellaneous bank administration costs are incurred regardless of whether FBC draws from the credit facility.

As noted above, FBC's interest rate forecasts are based on CDOR. An indirect result of the cessation of the publication of the London Interbank Offered Rate (LIBOR) is that Canada is planning to discontinue using CDOR as a risk-free rate benchmark for financial instruments in multiple asset classes. This will impact FBC's credit facility agreement as Refinitiv Benchmark Services (UK) Limited (RBSL), CDOR's regulated administrator, announced that CDOR will cease to be published after June 28, 2024.[48] The Canadian Alternative Reference Rate Working Group (CARR) was established to coordinate the transition to a new risk-free rate benchmark. In January

[48] https://www.bankofcanada.ca/markets/canadian-alternative-reference-rate-working-group/.

2023, CARR announced a development of a Term Canadian Overnight Repo Rate Average (Term CORRA), a risk-free interest rate benchmark for one- and three-month terms. Term CORRA is expected to replace CDOR and will become available in the latter half of 2023. As the Term CORRA rate is not yet available, FBC continues to use the CDOR methodology, consistent with its previous Annual Reviews, to forecast the short-term interest rate for 2024.

8.3.4 Interest Expense Forecast

The interest expense forecast reflects FBC's existing and forecast borrowing costs on long- and short-term debt.

Short-term interest expense is determined by applying the forecast short-term debt rate to the estimated short-term debt balance. Long-term debt interest expense is determined using the straight-line method by multiplying the average balance of the specific debenture by the debt coupon rate, or forecast coupon rate, if it is a new issue. The 2024 long-term debt schedule for FBC can be found in Section 11, Schedule 27.

8.3.5 Allowance for Funds Used During Construction (AFUDC)

FBC applies AFUDC to projects that are greater than three months in duration and greater than $100 thousand. Based on the above information, FBC's AFUDC rate for 2024 (which is equal to its after-tax weighted average cost of capital) is 5.75 percent. The calculation of the rate is shown in the following table.

Table 8-2: Calculation of AFUDC Rate for 2024

Description	Weight	Pre-Tax Rate	After-Tax Rate	Earned Return
Short Term Debt	5.46%	5.21%	3.80%	5.21%
Long Term Debt	54.54%	4.72%	3.45%	4.72%
Common Equity	40.00%	12.53%	9.15%	9.15%
Weighted Average	100.00%	7.87%	5.75%	6.52%

8.4 SUMMARY

FBC's equity financing and ROE have been forecast for 2024 at the same percentages as by Orders G-47-14 and G-129-16. FBC's debt financing costs on rate base are primarily determined by embedded rates on long-term debt, and to a lesser degree by short-term debt rates; the embedded rate on long-term debt is forecast to decrease in 2024 compared to 2023 (4.72 percent forecast for 2024 compared to 2023 Approved of 4.78 percent).

9. TAXES

9.1 INTRODUCTION AND OVERVIEW

This section discusses FBC's forecasts of property taxes and income tax which have been forecast on a basis consistent with prior years. In 2024, property taxes are forecast to increase by $0.313 million (1.7 percent) from 2023 Approved, while income tax is forecast to increase by $4.002 million (65.9 percent) compared to 2023 Approved.

9.2 PROPERTY TAXES

The 2024 Forecast of property taxes is approximately $18.573 million and is based on the Company's forecasts of assessed values of taxable assets, mill rates and taxes from revenues earned from electricity consumed within municipalities. A breakdown of property taxes by asset type is provided in Table 9-1 below.

Table 9-1: Property Taxes ($ millions)

Line No	Description	Approved 2023	Projected 2023	Forecast 2024
1	Generation Plant	$ 3.253	$ 3.201	$ 3.259
2	Transmission and Distribution	7.189	7.104	7.317
3	Substation Equipment	4.208	4.204	4.328
4	Land and Buildings	1.322	1.438	1.532
5	In Lieu	2.288	2.301	2.137
6	Total Property Taxes	$ 18.260	$ 18.248	$ 18.573
7				
8	2024 Forecast Change from 2023 Approved			1.7%
9	2024 Forecast Change from 2023 Projected			1.8%

As shown in the above table, in 2024 property taxes are forecast to increase by 1.7 percent from 2023 Approved and by 1.8 percent from 2023 Projected. In general, the 2024 increase from 2023 Projected is due to construction activities, market value changes, and changes in tax policies of local taxing authorities. The most significant drivers of the forecast changes are as follows:

1. ***Changes in Tax Rates.*** Tax Rates are expected to change for 2024 as follows:
    a) Municipal rates are expected to increase by 0.6 percent;
    b) School rates are expected to decrease by 1.2 percent;
    c) Rural rates are expected to decrease by 0.5 percent;
    d) Tax rates on First Nations are expected to increase by 0.8 percent; and
    e) Other rates are expected to decrease by 1.1 percent.

2. ***Changes in Revenues to Calculate Grants In Lieu of Taxes.*** Revenues reported to municipalities are expected to decrease by 7.1 percent based on actual revenues applicable to the taxation year. Grants in-lieu of taxes are based on a fixed percentage of revenues; the overall actual decrease in revenues reported to municipalities decreases the grants in-lieu of taxes due.

3. ***Changes in Assessed Values.*** Forecast changes in the assessed values of FBC's property are based on expected inflationary increases. These include:

   a) A 5.2 percent increase in assessed values of distribution lines and a 4.7 percent increase in transmission lines;

   b) A 4.1 percent increase in assessed values for generating facilities calculated using legislated cost manuals for valuing generating facilities;

   c) A 2.1 percent decrease in assessed values for substations calculated using legislated cost manuals for valuing substations; and

   d) A 7.1 percent increase for offices.

Any variances from the forecast of property taxes included in rates are recorded in the Flow-through deferral account and will be returned to or recovered from customers in the following year.

9.3 INCOME TAX

FBC is subject to corporate income taxes imposed by the Federal and BC governments. Current income taxes have been calculated using the flow-through (taxes payable) method, consistent with BCUC-approved past practice, at the corporate tax rate of 27 percent for 2023, which is unchanged from 2022. The corporate tax rates used in this Application are based on the *Canada Income Tax Act* and the *BC Income Tax Act* enacted legislation and are updated each year as part of the annual rate setting process.

Income tax for 2024 is forecast to increase by $4.002 million or 65.9 percent compared to 2023 Approved. The largest driver of the increase in 2024 is the lower income tax deductible through capital cost allowance (CCA) by approximately $2.849 million. The lower deductibility is partly due to reduced undepreciated capital cost (UCC) additions in higher rate CCA classes in the 2024 Forecast compared to 2023 Approved, and partly due to the phase-out of Canada's Accelerated Investment Incentive starting from 2024 (i.e., enhanced 50 percent first-year allowance to be phased out in 2024).[49] Income tax is also higher as a result of higher 2024 Forecast earned return and depreciation expense, which is partially offset by lower amortization of deferred charges.

[49] https://www.canada.ca/en/revenue-agency/services/tax/businesses/topics/sole-proprietorships-partnerships/report-business-income-expenses/claiming-capital-cost-allowance/accelerated-investment-incentive.html#AppPhaseOut.

Any tax rate variances and variances in income taxes on items that are flowed through in rates are subject to flow-through treatment.

All other differences in income tax expense are subject to earnings sharing.

9.4 SUMMARY

FBC has forecast its property and income taxes on a basis consistent with prior years, utilizing enacted legislation for income taxes and forecast changes for property tax rates and assessments.

10. EARNINGS SHARING

In the MRP Decision (at page 82), the BCUC approved an earnings sharing mechanism from 2020 to 2024 whereby 50 percent of the achieved ROE above or below the allowed ROE will be shared with customers. Since FBC is unable to determine final earnings sharing until all items required for the ROE calculation are known, including the final rate base, there is a lag in when FBC distributes earnings sharing amounts. This is consistent with the calculations of formula O&M, where the true-up of the formula inputs happens only once actuals are known. Thus, for 2024 rates, it is the 2022 formula O&M and 2022 earnings sharing amounts that are calculated and impact rates in 2024.

For 2024, FBC proposes to distribute a $2.396 million pre-tax credit ($1.749 million after-tax) to customers, comprised of:

- The $1.749 million credit difference between the projected 2022 deferral account after-tax addition of zero embedded in 2023 rates, and the actual 2022 deferral account after-tax credit addition of $1.749 million as provided in FBC's 2022 Annual Report to the BCUC. This amount is also shown in the opening 2024 balance[50] in the financial schedules in the Application.

FBC proposes to distribute $2.396 million to customers in 2024 as a reduction in 2024 revenue requirements through amortization of the projected 2024 opening after-tax balance of $1.749 million in the MRP Earnings Sharing deferral account.

As part of future rate filings, the actual earnings sharing for 2023 will be distributed to or collected from customers in a similar manner as described above, which will account for the actual 2023 ROE variance from approved.

[50] Section 11, Schedule 12.2, Line 14, Column 2.

11. FINANCIAL SCHEDULES

Description	Schedule Reference
Summary Of Rate Change	1
Rate Base	
Utility Rate Base	2
Formula Inflation Factors	3
Capital Expenditures	4
Capital Expenditures To Plant Reconciliation	5
Plant In Service Continuity Schedule	6
Accumulated Depreciation Continuity Schedule	7
Schedule Not Applicable	8
Contributions In Aid Of Construction Continuity Schedule	9
Schedule Not Applicable	10
Unamortized Deferred Charges And Amortization - Rate Base	11
Unamortized Deferred Charges And Amortization - Non-Rate Base	12
Working Capital Allowance	13
Cash Working Capital	14
Schedule Not Applicable	15
Revenue Requirement	
Utility Income And Earned Return	16
Volume And Revenue	17
Revenue At Existing And Revised Rates	18
Cost Of Energy	19
Operating And Maintenance Expense	20
Depreciation And Amortization Expense	21
Property And Sundry Taxes	22
Other Revenue	23
Income Taxes	24
Capital Cost Allowance	25
Return On Capital	26
Embedded Cost Of Long Term Debt	27

FORTISBC INC. FBC Annual Review for 2024 Rates - August 4, 2023 Section 11

SUMMARY OF RATE CHANGE Schedule 1
FOR THE YEAR ENDING DECEMBER 31, 2024
($millions)

Line No.	Particulars	2024 Forecast		Cross Reference
	(1)	(2)	(3)	(4)
1	**VOLUME/REVENUE RELATED**			
2	Customer Growth and Volume	$ (2.304)		
3	Change in Other Revenue	0.149	(2.155)	
4				
5	**POWER SUPPLY**			
6	Power Purchases	10.119		
7	Wheeling	0.337		
8	Water Fees	0.971	11.427	
9				
10	**O&M CHANGES**			
11	Gross O&M Change	1.655		
12	Capitalized Overhead Change	(0.248)	1.407	
13				
14	**DEPRECIATION EXPENSE**			
15	Depreciation from Net Additions		2.579	
16				
17	**AMORTIZATION EXPENSE**			
18	CIAC from Net Additions	(0.242)		
19	Deferrals	0.487	0.245	
20				
21	**FINANCING AND RETURN ON EQUITY**			
22	Financing Rate Changes	0.346		
23	Financing Ratio Changes	(0.056)		
24	Rate Base Growth	2.566	2.856	
25				
26	**TAX EXPENSE**			
27	Property and Other Taxes	0.313		
28	Other Income Taxes Changes	4.002	4.315	
29				
30	**REVENUE DEFICIENCY (SURPLUS)**		**$ 20.674**	Schedule 16, Line 6, Column 4
31				
32	Revenue at Existing Rates		428.377	Schedule 18, Line 7, Column 3
33	Rate Change		4.83%	

FORTISBC INC.

UTILITY RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Schedule 2

Line No.	Particulars	2023 Approved	2024 at Revised Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	Plant in Service, Beginning	$ 2,375,297	$ 2,505,386	$ 130,089	Schedule 6.1, Line 32, Column 3
2	Opening Balance Adjustment	-	-	-	Schedule 6.1, Line 32, Column 4
3	Net Additions	133,903	96,482	(37,421)	Schedule 6.1, Line 32, Column 5+6+7
4	Plant in Service, Ending	2,509,200	2,601,868	92,668	
5					
6	Accumulated Depreciation Beginning	$ (693,759)	$ (741,726)	$ (47,967)	Schedule 7.1, Line 32, Column 5
7	Opening Balance Adjustment	-	-	-	Schedule 7.1, Line 32, Column 6
8	Net Additions	(48,025)	(52,613)	(4,588)	Schedule 7.1, Line 32, Column 7+8+9
9	Accumulated Depreciation Ending	(741,784)	(794,339)	(52,555)	
10					
11	CIAC, Beginning	$ (243,101)	$ (254,724)	$ (11,623)	Schedule 9, Line 3, Column 2
12	Opening Balance Adjustment	-	-	-	
13	Net Additions	(11,628)	(7,539)	4,089	Schedule 9, Line 3, Column 5+6
14	CIAC, Ending	(254,729)	(262,263)	(7,534)	
15					
16	Accumulated Amortization Beginning - CIAC	$ 89,140	$ 94,207	$ 5,067	Schedule 9, Line 7, Column 2
17	Opening Balance Adjustment	-	-	-	
18	Net Additions	5,067	5,309	242	Schedule 9, Line 7, Column 5+6
19	Accumulated Amortization Ending - CIAC	94,207	99,516	5,309	
20					
21	Net Plant in Service, Mid-Year	$ 1,567,236	$ 1,623,963	$ 56,727	
22					
23	Adjustment for timing of Capital additions	$ 22,720	$ 2,750	$ (19,970)	
24	Capital Work in Progress, No AFUDC	34,306	25,574	(8,732)	
25	Unamortized Deferred Charges	40,045	51,287	11,242	Schedule 11, Line 34, Column 8
26	Working Capital	6,099	6,510	411	Schedule 13, Line 9, Column 3
27	Utility Plant Acquisition Adjustment	4,563	4,377	(186)	
28					
29	Mid-Year Utility Rate Base	$ 1,674,969	$ 1,714,461	$ 39,492	

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Schedule 3

FORMULA INFLATION FACTORS
FOR THE YEARS ENDING DECEMBER 31, 2020 to 2024
($000s)

Line No.	Particulars	Reference	2020	2021	2022	2023	2024	Total for 2024 Rate Setting	Cross Ref
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**Formula Cost Drivers**								
2	CPI		2.692%	1.596%	1.281%	4.940%	6.031%		
3	AWE		2.881%	5.745%	6.455%	3.944%	2.609%		
4	Labour Split								
5	Non Labour		38.000%	38.000%	37.000%	40.000%	43.000%		
6	Labour		62.000%	62.000%	63.000%	60.000%	57.000%		
7	CPI/AWE	(Line 2 x Line 5) + (Line 3 x Line 6)	2.809%	4.168%	4.541%	4.342%	4.080%		
8	Productivity Factor	G-166-20	-0.500%	-0.500%	-0.500%	-0.500%	-0.500%		
9	Net Inflation Factor	Line 7 + Line 8	2.309%	3.668%	4.041%	3.842%	3.580%		
10									
11									
12	**Growth in Average Customer Calculation**								
13	Actual/Projected Prior Year Average Customers		139,916	142,321	144,877	147,112	149,677		
14	Average Customers for the Year	Schedule 18, Line 7, Column 6	142,321	144,877	147,112	149,677	152,006		
15	Change in Average Customers	Line 14 - Line 13	2,405	2,556	2,235	2,565	2,329	12,090	
16									
17	Customer Growth Factor Multiplier	G-166-20						75%	
18	Change in Average Customers for Rate Setting Purposes	Line 15 x Line 17						9,068	
19									
20	Average Customers Used to Determine Starting UCOM	Line 13 Year 2020						139,916	
21									
22	Average Customer Forecast - 2024 Rate Setting Purposes	Line 18 + Line 20						148,984	

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Schedule 4

CAPITAL EXPENDITURES
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Line No.	Particulars	Total CapEx	Cross Reference
	(1)	(2)	(3)
1	**Forecast Capital Expenditures**		
2	Growth Capital	$ 24,568	
3	Sustainment Capital	51,652	
4	Other Capital	17,213	
5	Total Forecast Capital	$ 93,433	
6			
7	**Flow-Through Capital Expenditures**		
8	EV Charging Stations	$ 500	
9			
10	**Total Regular Capital Expenditures**	$ 93,933	

CAPITAL EXPENDITURES TO PLANT RECONCILIATION
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Schedule 5

Line No.	Particulars	2024 Formula		Cross Reference
	(1)	(2)		(3)
1	**CAPEX**			
2	Forecast Capital Expenditures	$	93,433	
3	Flow-Through Capital		500	
4	Total Regular Capital Expenditures	$	93,933	Schedule 4, Line 10, Column 2
5				
6	**Special Projects and CPCN's**			
7				
8	Total Special Projects and CPCN's	$	-	
9				
10	**Total Capital Expenditures**	$	93,933	
11				
12				
13	**RECONCILIATION OF CAPITAL EXPENDITURES TO PLANT**			
14				
15	Regular Capital Expenditures	$	93,933	Line 4
16	Add - Capitalized Overheads		11,148	Schedule 20, Line 23, Column 4
17	Add - AFUDC		241	
18	Gross Capital Expenditures	$	105,322	
19	Change in Work in Progress		-	
20	**Total Regular Additions to Plant**	$	105,322	
21				
22	Special Projects and CPCN's Capital Expenditures	$	-	Line 8
23	Add - AFUDC		1	
24	Gross Capital Expenditures		1	
25	Change in Work in Progress		5,499	
26	**Total Special Projects and CPCN Additions to Plant**	$	5,500	
27				
28	**Grand Total Additions to Plant**	$	110,822	Schedule 6.1, Line 32, Columns 5 + 6

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PLANT IN SERVICE CONTINUITY SCHEDULE Schedule 6
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Line No.	Account	Particulars	12/31/2023	Opening Bal Adjustment	CPCN's	Additions	Retirements	12/31/2024	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1		**Hydraulic Production Plant**							
2	330	Land Rights	$ 962	$ -	$ -	$ -	$ -	$ 962	
3	331	Structures and Improvements	22,199	-	-	166	(12)	22,353	
4	332	Reservoirs, Dams & Waterways	139,590	-	2,731	7,690	(777)	149,234	
5	333	Water Wheels, Turbines and Gen.	106,005	-	-	694	(141)	106,558	
6	334	Accessory Equipment	51,447	-	-	128	(38)	51,537	
7	335	Other Power Plant Equipment	48,576	-	-	5	(1)	48,580	
8	336	Roads, Railroads and Bridges	1,287	-	-	-	-	1,287	
9			$ 370,066	$ -	$ 2,731	$ 8,683	$ (969)	$ 380,511	
10									
11		**Transmission Plant**							
12	350	Land Rights-R/W	$ 10,884	$ -	$ -	$ 118	$ -	$ 11,002	
13	350.1	Land Rights-Clearing	10,109	-	-	118	-	10,227	
14	353	Station Equipment	264,083	-	2,769	3,420	(303)	269,969	
15	355	Poles Towers & Fixtures	134,762	-	-	6,403	(289)	140,876	
16	356	Conductors and Devices	129,994	-	-	6,403	(310)	136,087	
17	359	Roads and Trails	959	-	-	-	-	959	
18			$ 550,791	$ -	$ 2,769	$ 16,462	$ (902)	$ 569,120	

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PLANT IN SERVICE CONTINUITY SCHEDULE Schedule 6.1
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Line No.	Account	Particulars	12/31/2023	Opening Bal Adjustment	CPCN's	Additions	Retirements	12/31/2024	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1		**Distribution Plant**							
2	360	Land Rights-R/W	$ 7,995	$ -	$ -	$ 810	$ -	$ 8,805	
3	360.1	Land Rights-Clearing	12,001	-	-	372	-	12,373	
4	362	Station Equipment	324,416	-	-	12,969	(879)	336,506	
5	364	Poles Towers & Fixtures	271,743	-	-	13,565	(577)	284,731	
6	365	Conductors and Devices	456,680	-	-	20,383	(722)	476,341	
7	368	Line Transformers	205,825	-	-	14,062	(1,803)	218,084	
8	369	Services	9,521	-	-	-	-	9,521	
9	370.1	AMI Meters	41,986	-	-	528	-	42,514	
10	371	Installation on Customers' Premises	938	-	-	-	-	938	
11	373	Street Lighting and Signal System	14,304	-	-	168	(42)	14,430	
12	372	EV Stations Kiosks & Charger Connectors	6,265	-	-	-	-	6,265	
13			$ 1,351,674	$ -	$ -	$ 62,857	$ (4,023)	$ 1,410,508	
14									
15		**General Plant**							
16	389	Land	$ 11,268	$ -	$ -	$ -	$ -	$ 11,268	
17	390.1	Structures - Masonry	50,339	-	-	2,765	(317)	52,787	
18	390.2	Operation Building	20,014	-	-	605	(22)	20,597	
19	390.9	Leasehold Improvements	3,727	-	-	-	-	3,727	
20	391	Office Furniture & Equipment	5,376	-	-	214	(5)	5,585	
21	391.1	Computer Hardware	13,899	-	-	3,305	(1,278)	15,926	
22	391.2	Computer Software	44,861	-	-	6,982	(4,254)	47,589	
23	391.2	AMI Software	13,436	-	-	(3)	-	13,433	
24	392.1	Light Duty Vehicles	6,031	-	-	545	(481)	6,095	
25	392.1	Heavy Duty Vehciles	29,840	-	-	1,512	(348)	31,004	
26	394	Tools and Work Equipment	8,637	-	-	719	(658)	8,698	
27	397	Communication Structures & Equipment	14,926	-	-	676	(836)	14,766	
28	397.1	Fibre	5,531	-	-	-	(247)	5,284	
29	397.2	AMI Communications Structure & Equipment	4,970	-	-	-	-	4,970	
30			$ 232,855	$ -	$ -	$ 17,320	$ (8,446)	$ 241,729	
31									
32		**Total Plant in Service**	$ 2,505,386	$ -	$ 5,500	$ 105,322	$ (14,340)	$ 2,601,868	
33									
34		Cross Reference			Schedule 5, Line 26, Column 2	Schedule 5, Line 20, Column 2			

FORTISBC INC.

ACCUMULATED DEPRECIATION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Line No.	Account	Particulars	Gross Plant for Depreciation	Depreciation Rate	12/31/2023	Opening Bal Adjustment	Depreciation Expense	Retirements	Cost of Removal	Adjustments	12/31/2024	Cross Ref
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
1		**Hydraulic Production Plant**										
2	330	Land Rights	$ 962	1.07%	$ (372)	$ -	$ 10	$ -	$ -	$ -	$ (362)	
3	331	Structures and Improvements	22,199	1.68%	6,076	-	373	(12)	-	-	6,437	
4	332	Reservoirs, Dams & Waterways	142,321	1.90%	7,167	-	2,704	(777)	(1,894)	-	7,200	
5	333	Water Wheels, Turbines and Gen.	106,005	1.79%	22,308	-	1,897	(141)	(3)	-	24,061	
6	334	Accessory Equipment	51,447	3.13%	16,560	-	1,610	(38)	(133)	-	17,999	
7	335	Other Power Plant Equipment	48,576	2.12%	21,200	-	1,030	(1)	-	-	22,229	
8	336	Roads, Railroads and Bridges	1,287	1.44%	495	-	19	-	-	-	514	
9			$ 372,797		$ 73,434	$ -	$ 7,643	$ (969)	$ (2,030)	$ -	$ 78,078	
10												
11		**Transmission Plant**										
12	350	Land Rights-R/W	$ 10,884	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
13	350.1	Land Rights-Clearing	10,109	1.27%	2,612	-	128	-	-	-	2,740	
14	353	Station Equipment	266,852	2.33%	107,657	-	6,218	(303)	(162)	-	113,410	
15	355	Poles Towers & Fixtures	134,762	2.52%	41,827	-	3,396	(289)	(479)	-	44,455	
16	356	Conductors and Devices	129,994	2.52%	26,379	-	3,275	(310)	(479)	-	28,865	
17	359	Roads and Trails	959	1.96%	451	-	19	-	-	-	470	
18			$ 553,560		$ 178,926	$ -	$ 13,036	$ (902)	$ (1,120)	$ -	$ 189,940	

FORTISBC INC.

ACCUMULATED DEPRECIATION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Schedule 7.1

Line No.	Account	Particulars	Gross Plant for Depreciation	Depreciation Rate	12/31/2023	Opening Bal Adjustment	Depreciation Expense	Retirements	Cost of Removal	Adjustments	12/31/2024	Cross Ref
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
1		**Distribution Plant**										
2	360	Land Rights-R/W	$ 7,995	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
3	360.1	Land Rights-Clearing	12,001	1.25%	3,080	-	150	-	-	-	3,230	
4	362	Station Equipment	324,416	2.61%	100,441	-	8,467	(879)	(159)	-	107,870	
5	364	Poles Towers & Fixtures	271,743	2.73%	86,032	-	7,419	(577)	(578)	-	92,296	
6	365	Conductors and Devices	456,680	2.38%	138,391	-	10,868	(722)	(933)	-	147,604	
7	368	Line Transformers	205,825	3.13%	49,872	-	6,442	(1,803)	(354)	-	54,157	
8	369	Services	9,521	0.51%	6,856	-	49	-	-	-	6,905	
9	370.1	AMI Meters	41,986	6.25%	15,488	-	2,624	-	-	-	18,112	
10	371	Installation on Customers' Premises	938	0.00%	937	-	-	-	-	-	937	
11	373	Street Lighting and Signal System	14,304	4.95%	6,919	-	708	(42)	-	-	7,585	
12	372	EV Stations Kiosks & Charger Connectors	6,265	10.00%	1,422	-	627	-	-	-	2,049	
13			$ 1,351,674		$ 409,438	$ -	$ 37,354	$ (4,023)	$ (2,024)	$ -	$ 440,745	
14												
15		**General Plant**										
16	389	Land	$ 11,268	0.00%	$ 34	$ -	$ -	$ -	$ -	$ -	$ 34	
17	390.1	Structures - Masonry	50,339	2.53%	14,019	-	1,274	(317)	-	-	14,976	
18	390.2	Operation Building	20,014	1.63%	7,376	-	326	(22)	-	-	7,680	
19	390.9	Leasehold Improvements	3,727	1.63%	2,747	-	61	-	-	-	2,808	
20	391	Office Furniture & Equipment	5,376	4.42%	1,503	-	238	(5)	-	-	1,736	
21	391.1	Computer Hardware	13,899	21.60%	4,422	-	3,002	(1,278)	-	-	6,146	
22	391.2	Computer Software	44,861	8.96%	16,106	-	4,020	(4,254)	-	-	15,872	
23	391.2	AMI Software	13,436	10.00%	8,971	-	1,344	-	-	-	10,315	
24	392.1	Light Duty Vehicles	6,031	3.81%	2,352	-	230	(481)	79	-	2,180	
25	392.1	Heavy Duty Vehciles	29,840	6.50%	9,582	-	1,940	(348)	-	-	11,174	
26	394	Tools and Work Equipment	8,637	4.11%	3,262	-	355	(658)	-	-	2,959	
27	397	Communication Structures & Equipment	14,926	3.44%	4,145	-	513	(836)	(5)	-	3,817	
28	397.1	Fibre	5,531	6.97%	2,687	-	386	(247)	-	-	2,826	
29	397.2	AMI Communications Structure & Equipment	4,970	6.67%	2,722	-	331	-	-	-	3,053	
30			$ 232,855		$ 79,928	$ -	$ 14,020	$ (8,446)	$ 74	$ -	$ 85,576	
31												
32		**Total**	$ 2,510,886		$ 741,726	$ -	$ 72,053	$ (14,340)	$ (5,100)	$ -	$ 794,339	
33												
34		Cross Reference	Schedule 6.1, Line 32, Column 3+4+5									

SCHEDULE NOT APPLICABLE

FORTISBC INC. FBC Annual Review for 2024 Rates - August 4, 2023 Section 11

Schedule 9

CONTRIBUTIONS IN AID OF CONSTRUCTION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Line No.	Particulars	12/31/2023	CPCN / Open Bal Adjt	Adjustment	Additions	Retirements	12/31/2024	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**CIAC**							
2	CIAC	$ 254,724	$ -	$ -	$ 7,539	$ -	$ 262,263	
3	**Total**	$ 254,724	$ -	$ -	$ 7,539	$ -	$ 262,263	
4								
5	**Amortization**							
6	Amortization	$ (94,207)	$ -	$ -	$ (5,309)	$ -	$ (99,516)	
7	**Total**	$ (94,207)	$ -	$ -	$ (5,309)	$ -	$ (99,516)	
8								
9	**Net CIAC**	$ 160,517	$ -	$ -	$ 2,230	$ -	$ 162,747	

SCHEDULE NOT APPLICABLE

FORTISBC INC. FBC Annual Review for 2024 Rates - August 4, 2023 Section 11

Schedule 11

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Line No.	Particulars	12/31/2023	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	12/31/2024	Mid-Year Average	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**1. Forecasting Variance Accounts**								
2	BCUC Levies Variance Account	$ 36	$ -	$ -	$ -	$ (36)	$ -	$ 18	
3									
4	**2. Rate Smoothing Accounts**								
5									
6	**3. Benefits Matching Accounts**								
7	Preliminary and Investigative Charges '	$ 2,923	$ -	$ 328	$ -	$ -	$ 3,251	$ 3,087	Note 1
8	Demand Side Management	41,573	-	15,436	(4,168)	(6,287)	46,554	44,063	
9	Deferred Debt Issue Costs	4,391	-	-	(110)	(196)	4,084	4,237	
10	2025 Multi-year Rate Plan Application	256	-	1,200	(324)	-	1,132	694	
11	2023 - 2027 DSM Expenditure Schedule	62	-	-	-	(16)	47	55	
12	Mandatory Reliability Standards 2024 Audit	-	-	375	(101)	(91)	183	91	
13	Joint Pole Use Audit 2023	356	-	-	-	(89)	267	312	
14	2021 Generic Cost of Capital Proceeding	770	-	-	-	-	770	770	
15	Annual Reviews for 2020-2024 Rates	49	-	90	(25)	(49)	66	58	
16	2021 Long Term Electric Resource Plan	329	-	-	-	(174)	155	242	
17	BCUC Initiated Inquiry Costs	(57)	-	-	-	57	-	(28)	
18	EV Fleet & Workplace Charging Funding Account	-	169	576	(155)	(17)	572	371	
19	Mandatory Reliability Standards 2021 Audit	78	-	-	-	(78)	-	39	
20		$ 50,730	$ 169	$ 18,005	$ (4,883)	$ (6,940)	$ 57,080	$ 53,991	
21									
22	**4. Retroactive Expense Accounts**								
23									
24	**5.Other Accounts**								
25	Pension and OPEB Liability	$ (5,046)	$ -	$ 5,220	$ -	$ -	$ 174	$ (2,436)	
26	COVID-19 Customer Recovery Fund	139	-	-	-	(70)	68	104	
27	Climate Change Operational Adaptation (CCOA)	164	-	192	(52)	(41)	263	214	
28	BC Cost of Living Credit	(370)	-	-	-	370	-	(185)	
29	Princeton Office Disposition	-	(406)	-	-	406	-	(203)	
30	PST Rebate on Select Machinery and Equipment	(431)	-	-	-	431	-	(216)	
31	Indigenous Relations Agreement (Huth Substation)	-	-	-	-	-	-	-	
32		$ (5,545)	$ (406)	$ 5,412	$ (52)	$ 1,096	$ 506	$ (2,722)	
33									
34	**Total Rate Base Deferral Accounts**	$ 45,221	$ (237)	$ 23,417	$ (4,935)	$ (5,880)	$ 57,586	$ 51,287	
35									

36 Note 1: Gross Additions for Preliminary and Investigative Charges are after transfers to Construction Work in Progress. Additions of $1.60 million - transfer of $1.272 million = $0.328 million.

FORTISBC INC. FBC Annual Review for 2024 Rates - August 4, 2023 Section 11

Schedule 12

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - NON-RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Line No.	Particulars	12/31/2023	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	12/31/2024	Mid-Year Average	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**Deferral Accounts Financed at Short Term Interest Rate**								
2									
3	**1. Forecasting Variance Accounts**								
4	Pension & Other Post Retirement Benefits (OPEB) Variance	$ (169)	$ -	$ -	$ -	$ (246)	$ (415)	$ (292)	
5									
6	**2. Rate Smoothing Accounts**								
7									
8	**3. Benefits Matching Accounts**								
9	Tariff Applications	86	-	75	(20)	(86)	54	70	
10									
11	**4. Retroactive Expense Accounts**								
12									
13	**5.Other Accounts**								
14									
15	**Total NRB Deferral Accounts at Short Term Interest**	$ (83)	$ -	$ 75	$ (20)	$ (332)	$ (361)	$ (222)	
16									
17	Financing Costs at STI	$ 27	$ -	$ (7)	$ -	$ (27)	$ (7)	$ 10	

FORTISBC INC.

Schedule 12.1

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - NON-RATE BASE cont'd
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Line No.	Particulars	12/31/2023	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	12/31/2024	Mid-Year Average	Cross Ref
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**Deferral Accounts Financed at Weighted Average Cost of Debt**								
2									
3	**1. Forecasting Variance Accounts**								
4									
5	**2. Rate Smoothing Accounts**								
6									
7	**3. Benefits Matching Accounts**								
8	CPCN Projects Preliminary Engineering [1]	$ 2,666	$ -	$ (255)	$ -	$ -	$ 2,411	$ 2,538	Note 1
9	2017 Rate Design Application	118	-	-	-	(118)	-	59	
10	2020 - 2024 Multi-Year Rate Plan Application	145	-	-	-	(145)	-	72	
11	Rate Design and Rates for Electric Vehicle Direct Current Fast Charging Service Application	68	-	-	-	(59)	9	38	
12		$ 2,996	$ -	$ (255)	$ -	$ (322)	$ 2,420	$ 2,707	
13									
14	**4. Retroactive Expense Accounts**								
15									
16	**5.Other Accounts**								
17									
18	**Total NRB Deferral Accounts at Weighted Average Cost of Debt**	$ 2,996	$ -	$ (255)	$ -	$ (322)	$ 2,420	$ 2,707	
19									
20	Financing Costs at WACD	$ 76	$ -	$ 95	$ -	$ (76)	$ 95	$ 86	

21 Note 1: Gross additions for CPCN Projects Preliminary Engineering after transfers to Construction Work in Progress.

FORTISBC INC.

Schedule 12.2

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - NON-RATE BASE cont'd
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Line No.	Particulars	12/31/2023	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	12/31/2024	Mid-Year Average	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**Deferral Accounts Financed at Weighted Average Cost of Capital**								
2									
3	**1. Forecasting Variance Accounts**								
4	2020 - 2024 Flow-Through Deferral Account	$ (6,520)	$ -	$ -	$ -	$ 6,520	$ -	$ (3,260)	
5									
6	**2. Rate Smoothing Accounts**								
7									
8	**3. Benefits Matching Accounts**								
9	EV Fleet & Workplace Charging Funding Account	$ 169	$ (169)	$ -	$ -	$ -	$ -	$ -	
10									
11	**4. Retroactive Expense Accounts**								
12									
13	**5.Other Accounts**								
14	MRP Earnings Sharing Account	$ (1,749)	$ -	$ -	$ -	$ 1,749	$ -	$ (875)	
15	Princeton Office Disposition	(406)	406	-	-	-	-	-	
16									
17	**Total NRB Deferral Accounts at Weighted Average Cost of Capital**	$ (8,506)	$ 237	$ -	$ -	$ 8,269	$ -	$ (4,135)	
18									
19	Financing Costs at AFUDC	$ (1,228)	$ -	$ (272)	$ -	$ 1,228	(272)	(750)	
20									
21	**Non Rate Base Deferral Accounts Non-Interest Bearing**	$ 50	$ -	$ -	$ -	$ -	$ 50	$ 50	
22									
23									
24	**Total Non Rate Base Deferral Accounts (including financing)**	$ (6,668)	$ 237	$ (364)	$ (20)	$ 8,740	$ 1,924	$ (2,254)	

FORTISBC INC.

FBC Annual Review for 2024 Rates - August 4, 2023

Section 11

Schedule 13

WORKING CAPITAL ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Line No.	Particulars	2023 Approved	2024 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Cash Working Capital**				
2	Cash Working Capital	$ 6,849	$ 7,367	$ 518	Schedule 14, Line 32, Column 5
3					
4	Add/Less: Funds Unavailable/(Funds Available)				
5	Customers Loans	353	306	(47)	
6	Employee Loans	570	509	(61)	
7	Inventories - Materials and Supplies	649	783	134	
8	Employee Withholdings	(2,322)	(2,455)	(133)	
9	Total	$ 6,099	$ 6,510	$ 411	

FORTISBC INC. FBC Annual Review for 2024 Rates - August 4, 2023 Section 11

Schedule 14

CASH WORKING CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Line No.	Particulars	2024 at Revised Rates	Lag (Lead) Days	Extended	Weighted Average Lag (Lead) Days	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)
1	**REVENUE**					
2	**Sales Revenue**					
3	Residential Tariff Revenue	$ 215,950	56.0	$ 12,093,200		
4	Commercial Tariff Revenue	116,156	45.1	5,238,636		
5	Wholesale Tariff Revenue	58,256	37.5	2,184,600		
6	Industrial Tariff Revenue	52,203	38.0	1,983,714		
7	Lighting Tariff Revenue	2,328	34.6	80,549		
8	Irrigation Tariff Revenue	4,158	47.0	195,426		
9						
10	**Other Revenue**					
11	Apparatus and Facilities Rental	$ 6,199	90.0	$ 557,894		
12	Contract Revenue	2,260	62.2	140,563		
13	Transmission Access Revenue	1,723	65.2	112,340		
14	Late Payment Charges	962	54.0	51,922		
15	Connection Charges	561	30.5	17,104		
16	Other Utility Income	388	63.4	24,606		
17	Total	$ 461,143		$ 22,680,554		49.2
18						
19	**EXPENSES**					
20	Power Purchases	$ 173,694	(51.5)	$ (8,945,261)		
21	Wheeling	7,324	(46.9)	(343,514)		
22	Water Fees	12,513	(1.4)	(17,518)		
23	Operating and Maintenance	63,174	(28.6)	(1,806,768)		
24	Property Taxes	18,573	(4.9)	(91,008)		
25	GST	703	(45.4)	(31,916)		
26	Income Tax	10,075	(15.2)	(153,140)		
27	Total	$ 286,057		$ (11,389,125)		(39.8)
28						
29	Net Lag (Lead) Days					9.4
30	Total Expenses				$	286,057
31						
32	Cash Working Capital				$	7,367

SCHEDULE NOT APPLICABLE

FORTISBC INC. FBC Annual Review for 2024 Rates - August 4, 2023 Section 11

UTILITY INCOME AND EARNED RETURN
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Schedule 16

Line No.	Particulars	2023 Approved	2024 Forecast at 2023 Approved Rates	Revised Revenue	2024 Forecast at Revised Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**ENERGY VOLUMES**						
2	Sales Volume (GWh)	3,475	3,474	-	3,474	(1)	Schedule 17, Line 8, Column 3
3							
4	**REVENUE**						
5	Sales	$ 426,073	$ 428,377	$ -	$ 428,377	$ 2,304	Schedule 17, Line 17, Column 3
6	Deficiency (Surplus)	-	-	20,674	20,674	20,674	
7	Total	426,073	428,377	20,674	449,051	22,978	Schedule 18, Line 7, Column 5
8							
9	**EXPENSES**						
10	Cost of Energy	$ 182,105	$ 193,532	$ -	$ 193,532	$ 11,427	Schedule 19, Line 29, Column 3
11	O&M Expense (net)	61,767	63,174	-	63,174	1,407	Schedule 20, Line 24, Column 4
12	Depreciation & Amortization	61,246	64,070	-	64,070	2,824	Schedule 21, Line 11, Column 3
13	Property Taxes	18,260	18,573	-	18,573	313	Schedule 22, Line 6, Column 3
14	Other Revenue	(12,241)	(12,092)	-	(12,092)	149	Schedule 23, Line 8, Column 3
15	Utility Income Before Income Taxes	114,936	101,120	20,674	121,794	6,859	
16							
17	Income Taxes	6,073	4,498	5,577	10,075	4,002	Schedule 24, Line 13, Column 3
18							
19	**EARNED RETURN**	$ 108,863	$ 96,622	$ 15,097	$ 111,719	$ 2,857	Schedule 26, Line 5, Column 7
20							
21	**UTILITY RATE BASE**	$ 1,674,969	$ 1,713,933		$ 1,714,461	$ 39,492	Schedule 2, Line 29, Column 3
22	**RATE OF RETURN ON UTILITY RATE BASE**	6.50%	5.64%		6.52%	0.02%	Schedule 26, Line 5, Column 6

FORTISBC INC. FBC Annual Review for 2024 Rates - August 4, 2023 Section 11

VOLUME AND REVENUE Schedule 17
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Line No.	Particulars	2023 Approved	2024 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**ENERGY VOLUME SOLD (GWh)**				
2	Residential	1,300	1,299	(1)	
3	Commercial	973	974	1	
4	Wholesale	579	590	11	
5	Industrial	575	564	(11)	
6	Lighting	9	9	-	
7	Irrigation	39	38	(1)	
8	Total	3,475	3,474	(1)	
9					
10	**REVENUE AT EXISTING RATES**				
11	Residential	$ 205,734	$ 206,007	$ 273	
12	Commercial	110,490	110,808	318	
13	Wholesale	54,100	55,574	1,474	
14	Industrial	49,759	49,800	41	
15	Lighting	2,295	2,221	(74)	
16	Irrigation	3,695	3,967	272	
17	Total	$ 426,073	$ 428,377	$ 2,304	

FORTISBC INC. FBC Annual Review for 2024 Rates - August 4, 2023 Section 11

REVENUE AT EXISTING AND REVISED RATES
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Schedule 18

Line No.	Particulars	2023 Approved Revenue	2024 Forecast: Revenue at 2023 Approved Rates	2024 Forecast: Effective Increase	2024 Forecast: Revenue at Revised Rates	Average Number of Customers	GWh	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	Residential	$ 205,734	$ 206,007	$ 9,943	$ 215,950	132,389	1,299	
2	Commercial	110,490	110,808	5,348	116,156	17,125	974	
3	Wholesale	54,100	55,574	2,682	58,256	6	590	
4	Industrial	49,759	49,800	2,403	52,203	42	564	
5	Lighting	2,295	2,221	107	2,328	1,341	9	
6	Irrigation	3,695	3,967	191	4,158	1,103	38	
7	Total	$ 426,073	$ 428,377	$ 20,674	$ 449,051	152,006	3,474	
8								
9	**Effective Increase**			4.83%				

FORTISBC INC. FBC Annual Review for 2024 Rates - August 4, 2023 Section 11

COST OF ENERGY Schedule 19
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Line No.	Particulars	2023 Approved	2024 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**POWER PURCHASES**				
2	Gross Load (GWh)	3,775	3,773	(2)	
3					
4	**Power Purchase Expense**				
5	Brilliant	$ 44,050	$ 44,433	$ 383	
6	BC Hydro PPA	71,302	71,680	378	
7	Waneta Expansion	41,834	40,365	(1,469)	
8	Market and Contracted Producers	6,326	16,972	10,646	
9	Independent Power Producers	62	245	183	
10	CPA Balancing Pool	-	0	0	
11	Total	$ 163,575	$ 173,694	$ 10,119	
12					
13	**WHEELING**				
14	**Wheeling Nomination (MW months)**				
15	Okanagan Point of Interconnection	2,670	2,595	(75)	
16	Creston	420	450	30	
17					
18	**Wheeling Expense**				
19	Okanagan Point of Interconnect	$ 5,555	$ 5,813	$ 258	
20	Creston	570	658	88	
21	Other	863	854	(9)	
22	Total	$ 6,987	$ 7,324	$ 337	
23					
24	**WATER FEES**				
25	Plant Entitlement Use in previous year (GWh)	1,571	1,561	(10)	
26					
27	Water Fees	$ 11,543	$ 12,513	$ 971	
28					
29	Total	$ 182,105	$ 193,532	$ 11,427	

FORTISBC INC. FBC Annual Review for 2024 Rates - August 4, 2023 Section 11

Schedule 20

OPERATING AND MAINTENANCE EXPENSE
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Line No.	Particulars	Inflation Indexed O&M	Forecast O&M	Total O&M	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Inflation Indexed O&M**				
2	2023 Base Unit Cost O&M	$ 472			
3	2024 Net Inflation Factor	3.580%			Schedule 3, Line 9, Column 7
4	2024 Base Unit Cost O&M	$ 489			Line 2 x (1 + Line 3)
5					
6	2024 Average Customer Forecast - Rate Setting Purpose	148,984			Schedule 3, Line 22, Column 8
7					
8	2024 Inflation Indexed O&M before prior year True-up	$ 72,853			Line 4 x Line 6 / 1,000
9					
10	2022 Average Customer True-up	(30)			
11					
12	2024 Inflation Indexed O&M	$ 72,823		$ 72,823	Sum of Lines 8 and 10
13					
14	**O&M Tracked Outside of Formula**				
15	Pension & OPEB (O&M Portion)		$ (2,532)		
16	Insurance Premiums		2,678		
17	BCUC Levies		458		
18	MRS		585		
19	EV Charging Stations		310		
20	Sub-total		$ 1,499	1,499	Sum of Lines 15 through 19
21					
22	**Total Gross O&M**			$ 74,322	Line 12 + Line 20
23	Capitalized Overhead			(11,148)	-15 % x Line 22
24	**Net O&M Expense**			$ 63,174	Sum of Lines 22 and 23

DEPRECIATION AND AMORTIZATION EXPENSE
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Line No.	Particulars	2023 Approved	2024 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Depreciation**				
2	Depreciation Expense	$ 69,474	$ 72,053	$ 2,579	Schedule 7.1, Line 32, Column 7
3					
4	**Amortization**				
5	Rate Base Deferrals	$ 6,716	$ 5,880	$ (836)	Schedule 11, Line 34, Column 6
6	Non-Rate Base Deferrals	(10,063)	(8,740)	1,323	Schedule 12.2, Line 24, Column 6
7	Utility Plant Acquisition Adjustment	186	186	-	
8	CIAC	(5,067)	(5,309)	(242)	Schedule 9, Line 7, Column 5
9		(8,228)	(7,983)	245	
10					
11	Total	$ 61,246	$ 64,070	$ 2,824	

FORTISBC INC.

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Section 11

Schedule 22

PROPERTY AND SUNDRY TAXES
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Line No.	Particulars	2023 Approved	2024 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	Generating Plant	$ 3,253	$ 3,259	$ 6	
2	Transmission and Distribution	7,189	7,317	128	
3	Substation Equipment	4,208	4,328	120	
4	Land and Buildings	1,322	1,532	210	
5	1% In-Lieu of Municipal Taxes	2,288	2,137	(151)	
6	Total	$ 18,260	$ 18,573	$ 313	

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OTHER REVENUE Schedule 23
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Line No.	Particulars	2023 Approved	2024 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	Apparatus and Facilities Rental	$ 6,108	$ 6,199	$ 91	
2	Contract Revenue	2,367	2,260	(107)	
3	Transmission Access Revenue	1,834	1,723	(111)	
4	Interest Income	30	37	7	
5	Late Payment Charges	994	962	(32)	
6	Connection Charges	553	561	8	
7	Other Recoveries	355	351	(4)	
8	Total	$ 12,241	$ 12,092	$ (149)	

FORTISBC INC.

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Section 11

Schedule 24

INCOME TAXES
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Line No.	Particulars	2023 Approved	2024 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**EARNED RETURN**	$ 108,863	$ 111,719	$ 2,856	Schedule 16, Line 19, Column 5
2	Deduct: Interest on Debt	(47,559)	(48,970)	(1,411)	Schedule 26, Line 1+2, Column 7
3	Adjustments to Taxable Income	(44,884)	(35,508)	9,376	Line 32
4	Accounting Income After Tax	$ 16,420	$ 27,241	$ 10,821	
5					
6	1 - Current Income Tax Rate	73.00%	73.00%	0.00%	
7	Taxable Income	$ 22,493	$ 37,316	$ 14,823	
8					
9	Current Income Tax Rate	27.00%	27.00%	0.00%	
10	Income Tax - Current	$ 6,073	$ 10,075	$ 4,002	
11					
12	Previous Year Adjustment	-	-	-	
13	**Total Income Tax**	$ 6,073	$ 10,075	$ 4,002	
14					
15					
16	**ADJUSTMENTS TO TAXABLE INCOME**				
17	Addbacks:				
18	Depreciation	$ 69,474	$ 72,053	$ 2,579	Schedule 21, Line 2, Column 3
19	Amortization of Deferred Charges	(3,347)	(2,860)	487	Schedule 21, Line 5+6, Column 3
20	Amortization of Utility Plant Acquisition Adjustment	186	186	-	Schedule 21, Line 7, Column 3
21	Pension Expense	(528)	(1,501)	(973)	
22	OPEB Expense	1,119	844	(275)	
23					
24	Deductions:				
25	Capital Cost Allowance	(89,602)	(81,899)	7,703	Schedule 25, Line 18, Column 6
26	CIAC Amortization	(5,067)	(5,309)	(242)	Schedule 21, Line 8, Column 3
27	Pension Contributions	(4,203)	(3,811)	392	
28	OPEB Contributions	(705)	(752)	(47)	
29	Overheads Capitalized Expensed for Tax Purposes	(10,900)	(11,148)	(248)	Schedule 20, Line 23, Column 4
30	Removal Costs	(1,200)	(1,200)	-	
31	All Other	(111)	(111)	-	
32	Total	$ (44,884)	$ (35,508)	$ 9,376	

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Schedule 25

CAPITAL COST ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Line No.	Class	CCA Rate	12/31/2023 UCC Balance	2024 Additions & Opening Adjt	Adjustment	2024 CCA	Forecast 12/31/2024 UCC Balance
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	1(a)	4%	$ 147,922	$ -	$ -	$ (5,917)	$ 142,005
2	1(b)	6%	33,070	3,010	-	(2,165)	33,915
3	2	6%	10,719	-	-	(643)	10,076
4	3	5%	616	-	-	(31)	585
5	6	10%	2	-	-	-	2
6	8	20%	3,538	833	-	(874)	3,497
7	10	30%	4,308	1,838	-	(1,844)	4,302
8	13	0%	11	-	-	-	11
9	14.1 (pre 2017)	7%	6,441	-	-	(451)	5,990
10	14.1 (post 2016)	5%	4,926	1,266	-	(310)	5,882
11	17	8%	161,210	8,533	-	(13,579)	156,164
12	42	12%	8,987	604	-	(1,151)	8,440
13	43.1	30%	477	-	-	(143)	334
14	46	30%	1,896	-	-	(569)	1,327
15	47	8%	530,216	64,669	-	(47,591)	547,294
16	50	55%	2,869	9,188	-	(6,631)	5,426
17							
18	Total		$ 917,208	$ 89,941	$ -	$ (81,899)	$ 925,250

FORTISBC INC. FBC Annual Review for 2024 Rates - August 4, 2023 Section 11

Schedule 26

RETURN ON CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Line No.	Particulars	2023 Approved Earned Return	Amount	Ratio	2024 Average Embedded Cost	Cost Component	Earned Return	Earned Return Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	Long Term Debt	$ 43,709	$ 935,137	54.54%	4.72%	2.57%	$ 44,097	$ 388	Schedule 27, Line 11, Column 6
2	Short Term Debt	3,850	93,540	5.46%	5.21%	0.28%	4,873	1,023	
3	Common Equity	61,304	685,784	40.00%	9.15%	3.66%	62,749	1,445	
4									
5	Total	$ 108,863	$ 1,714,461	100.00%		6.52%	$ 111,719	$ 2,856	
6									
7	Cross Reference		Schedule 2, Line 29, Column 3						

FORTISBC INC.

FBC Annual Review for 2024 Rates - August 4, 2023

Section 11

Schedule 27

EMBEDDED COST OF LONG TERM DEBT
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Line No.	Particulars	Issue Date	Maturity Date	Average Principal Outstanding	Interest Rate	Interest Expense	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	2005 Debt Issue - Series 1 - 05	November 9, 2005	November 9, 2035	$ 100,000	5.600%	$ 5,600	
2	2007 Debt Issue - Series 1 - 07	July 4, 2007	July 4, 2047	105,000	5.900%	6,195	
3	2009 Debt Issue - MTN - 09	June 2, 2009	June 2, 2039	105,000	6.100%	6,405	
4	2010 Debt Issue - MTN - 10	November 24, 2010	November 24, 2050	100,000	5.000%	5,000	
5	2014 Debt Issue - MTN - 14	October 28, 2014	October 28, 2044	200,000	4.000%	8,000	
6	2017 Debt Issue - MTN - 17	December 4, 2017	December 6, 2049	75,000	3.620%	2,715	
7	2020 Debt Issue - MTN - 20	May 11, 2020	May 11, 2050	75,000	3.120%	2,340	
8	2022 Debt Issue - MTN - 22	March 14, 2022	March 14, 2052	100,000	4.160%	4,160	
9	2024 Debt Issue - MTN - 24	April 1, 2024	April 1, 2054	75,137	4.900%	3,682	
10							
11	Total			$ 935,137		$ 44,097	
12							
13	Average Embedded Cost				4.72%		

12. ACCOUNTING MATTERS

12.1 INTRODUCTION AND OVERVIEW

In this section, FBC discusses "Exogenous Factors" under its MRP. FBC also discusses emerging accounting guidance, and the status of its non-rate base deferral accounts. With respect to its non-rate base deferral accounts, FBC provides information on the Flow-through deferral account.

12.2 EXOGENOUS (Z) FACTORS

FBC is permitted to adjust the cost of service for "Exogenous Factors" under the MRP. The BCUC established the following criteria for evaluating whether the impact of an event qualifies for exogenous factor treatment:

1. The costs/savings must be attributable entirely to events outside the control of a prudently operated utility;
2. The costs/savings must be directly related to the exogenous event and clearly outside the base upon which the rates were originally derived;
3. The impact of the event was unforeseen;
4. The costs must be prudently incurred; and
5. The costs/savings related to each exogenous event must exceed the BCUC-defined materiality threshold.

The materiality threshold (item 5) for FBC has been established at $0.150 million, as approved in the MRP Decision.

In 2022 and thus far in 2023, FBC has not identified any items that merit exogenous factor treatment.

12.3 ACCOUNTING MATTERS

In the following section, FBC provides information on emerging accounting guidance.

12.3.1 Emerging Accounting Guidance

In the 2014-2019 PBR Plan Decision and Order G-139-14, the BCUC directed FBC to "communicate any accounting policy changes and updates to the Commission and other stakeholders as part of the Annual Review process during the PBR period." While this directive was not included as part of the MRP Decision, FBC will continue to provide accounting policy changes and updates as part of the Annual Review materials.

There are no new accounting policy changes that FBC is proposing, or that are required to be implemented under US GAAP, that result in a change in accounting for 2024.

12.4 NON-RATE BASE DEFERRAL ACCOUNTS

FBC maintains both rate base and non-rate base deferral accounts. Rate base deferral accounts are included in rate base and earn a rate base return. In contrast, non-rate base deferral accounts are outside of rate base and may have varying rates of return, depending on the nature of the account and the return approved by the BCUC.

In the following section, FBC provides information on its Flow-through deferral account. Information on FBC's non-rate base earnings sharing deferral account is included in Section 10.

12.4.1 New Deferral Accounts

FBC is not seeking approval of any new non-rate base deferral accounts in this Application.

12.4.2 Existing Deferral Accounts

In the section below, FBC discusses the Flow-through deferral account.

12.4.2.1 Flow-Through Deferral Account (2020-2024)

As approved by Order G-166-20, the Flow-through deferral account is used to capture the annual variances between the approved and actual amounts for all costs and revenues which are forecast annually, are not subject to earnings sharing, and which do not have a previously approved deferral account. The specific items included in the Flow-through deferral account were set out in Table C4-1 of the MRP Application, reproduced below.

Table 12-1: Variances Captured in the Flow-through Deferral Account

	FEI	FBC
Delivery Revenues (FEI):		
Residential and commercial use rate variances	RSAM	N/A
Customer variances	Flow-through deferral	N/A
Industrial and all other revenue variances	Flow-through deferral	N/A
Revenues and Power Supply (FBC):		
Revenue variances	N/A	Flow-through deferral
Power Supply variances net of PSI	N/A	Flow-through deferral
Gross O&M:		
Index-based O&M variances	Subject to earnings sharing	Subject to earnings sharing
BCUC fees variances	BCUC variances deferral	BCUC variances deferral
Pension & OPEB variances	Pension/OPEB variances deferral	Pension/OPEB variances deferral
All other O&M variances [1,3]	Flow-through deferral	Flow-through deferral
Capitalized Overhead:		
Capitalized overhead variances	No variance	No variance
Depreciation and Amortization:		
Depreciation rate variances	No variance	No variance
Depreciation on Clean Growth Projects [2,3]	Flow-through deferral	Flow-through deferral
Other depreciation variances	Subject to earnings sharing	Subject to earnings sharing
Amortization of deferrals	No variance	No variance
Property Tax:		
Property tax variances	Flow-through deferral	Flow-through deferral
Other Revenues :		
SCP Mitigation revenues variances	SCP Revenues deferral	N/A
CNG/LNG Recoveries variances	CNG/LNG Recoveries deferral	N/A
Revenues from Clean Growth Projects [2,3]	Flow-through deferral	Flow-through deferral
All other other revenue/income variances	Subject to earnings sharing	Subject to earnings sharing
Interest Expense/Cost of Debt:		
Interest on RSAM/CCRA/MCRA/Gas storage	Interest on RSAM/CCRA/MCRA/Gas Storage	N/A
Interest rate variances	Flow-through deferral	Flow-through deferral
Interest on Clean Growth Projects [2,3]	Flow-through deferral	Flow-through deferral
Other interest variances	Subject to earnings sharing	Subject to earnings sharing
Income Tax:		
Income tax rate variances	Flow-through deferral	Flow-through deferral
Income tax on Clean Growth Projects [2,3]	Flow-through deferral	Flow-through deferral
Other income tax variances	Subject to earnings sharing	Subject to earnings sharing

1: Including items forecast outside of the formula such as insurance premiums, NGT stations, biomethane, variable LNG production, integrity digs and EV charging stations.
2: Cost of service for NGT fueling stations and tankers, variable LNG production, and EV stations will be captured in the Flow-through deferral account.
3: Biomethane other revenues will continue to capture the actual cost of service of the biomethane capital assets and transfer it to the BVA

In accordance with the method set out in the table above, the calculation of the 2023 Projected Flow-through amount of $2.898 million debit is shown in Table 12-2 below. To calculate the overall combined amount to be distributed to customers, FBC has also included the following adjustment:

- The $9.418 million credit difference between the projected ending 2022 deferral account credit balance of $9.693 million[51] embedded in 2023 rates, and the actual ending 2022 deferral credit balance of $19.111 million. A more detailed breakout of the 2022 variance is provided in Table 12-3 below. FBC notes that the financing return on this account is included in the aggregate financing of deferral accounts at Section 11, Schedule 12.2, Line 19.

Table 12-2: 2023 Projected Flow-through Deferral Account Additions ($ millions)

Line No.	Particulars	2023 Approved	2023 Projected	After-Tax Flow-Through Variance
	(1)	(2)	(3)	(4)
1	**Total Revenue**	$ (426.073)	$ (431.720)	$ (5.647)
2				
3	**Total Power Purchase Expense**	163.575	170.873	7.298
4				
5	**Total Wheeling**	6.987	7.294	0.307
6				
7	**Total Water Fees**	11.543	12.433	0.890
8				
9	**Net O&M Expense**			
10	Pension & OPEB	(1.297)	(1.297)	-
11	Insurance	2.457	2.507	0.050
12	BCUC Fees	0.385	0.385	-
13	MRS	0.585	0.585	-
14	EV Charging Stations	0.219	0.181	(0.038)
15	Capitalized Overhead	(10.900)	(10.900)	-
16				
17	**Depreciation and Amortization**			
18	Amortization of Deferrals	(3.347)	(3.347)	-
19	Depreciation variance on Clean Growth Projects/CPCNs/Exogenous Capital	-	-	-
20	CIAC Amortization variance on Clean Growth Projects/CPCNs/Exogenous Capital	-	-	-
21				
22	**Total Property Taxes**	18.260	18.248	(0.012)
23				
24	**Other Revenues**			
25	EV Carbon Credits	-	(0.544)	(0.544)
26				
27	**Interest Expense**			
28	Long-term debt interest expense variance	43.709	41.856	(1.853)
29	Interest variance on Clean Growth Projects/CPCNs/Exogenous Capital	-	-	-
30	Short-term debt rate variance	-	1.353	1.353
31	Short-term debt volume variance from long-term debt issue variance	-	2.166	2.166
32	Short-term debt timing variance from long-term debt issue timing	-	-	-
33				
34	**Income Tax Expense**			
35	Income tax variance on Clean Growth Projects/CPCNs/Exogenous Capital	-	-	-
36	Income tax/CCA rate changes	-	-	-
37	Income tax on taxable flowthrough variances above (excl. Clean Growth Projects/CPCNs/Exogenous Capital)	-	(1.072)	(1.072)
38				
39	**2023 After-Tax Flow-Through Addition to Deferral Account (excluding Financing)**			**2.898**
40				
41	2022 Ending Deferral Account Balance True-up			(9.418)
42				
43	**2024 After-Tax Amortization**			**(6.520)**

[51] FBC Annual Review for 2023 Rates, April 24, 2023 finalized financial schedules supporting 2023 Interim Rates, Schedule 12.2, Line 4, Column 2.

12.4.2.1.1 2023 PROJECTED FLOW-THROUGH VARIANCES

FBC provides the following explanations for the 2023 Projected flow-through variances shown in Table 12-2 above:

- The variance in revenue is due to increased sales from residential, commercial, and wholesale customers;
- The variance in power purchase expense is primarily due to increased Market and Contracted Purchases required to address supply gaps and reduce exposure to potentially extreme market prices. FBC purchased forward market blocks to cover projected capacity shortfalls in June 2023 and reduce exposure to Tranche 2 energy under the PPA with BC Hydro. FBC also purchased wholesale market power from the spot market, at rates economic to the PPA during the first six months of the year, to reduce required purchases above the BC Hydro PPA Nomination. Also included in the Projected 2023 expense are planned wholesale market purchases in November and December 2023, consistent with the strategy presented in the 2023/24 Annual Electric Contracting Plan (AECP);
- Variances in wheeling and water fees are discussed in Section 4;
- Flow-through O&M amounts are discussed in Section 6;
- Amortization expense is equal to the approved value;
- Variances in property taxes are described in Section 9;
- Variances in other revenues are described in Section 5;
- The projected interest expense variances are derived from FBC forecasting issuing long-term debt in 2023 in the Annual Review for 2023 Rates, whereas FBC is no longer projecting a debt issuance, and FBC projecting a higher short-term interest rate than the approved short-term interest rate, both as described in Section 8; and
- The income tax variance is derived as 27 percent of the aforementioned variances.

An adjustment to include the difference between the projected and final actual amounts for 2023 subject to flow-through will be recorded in the deferral account in 2023 and amortized in 2025 rates.

12.4.2.1.2 2022 FLOW-THROUGH DEFERRAL ACCOUNT TRUE-UP

Table 12-3 below provides a breakdown of the 2022 true-up amount of $9.418 million credit.

Table 12-3: 2022 Actual vs. Projected Flow-through Deferral Account Additions ($ millions)

Line No.	Particulars	2022 Projected	2022 Actual	After-Tax Flow-Through Variance
	(1)	(2)	(3)	(4)
1	**Total Revenue**	$ (414.385)	$ (425.782)	$ (11.397)
2				
3	**Total Power Purchase Expense**	153.164	153.457	0.293
4				
5	**Total Wheeling**	6.330	6.898	0.568
6				
7	**Total Water Fees**	11.916	11.838	(0.078)
8				
9	**Net O&M Expense**			
10	Pension & OPEB	(1.716)	(1.716)	-
11	Insurance	2.291	2.286	(0.005)
12	BCUC Fees	0.373	0.373	-
13	MRS	0.500	0.468	(0.032)
14	EV Charging Stations	0.187	0.213	0.026
15	COVID-19 Pandemic	(1.030)	(1.030)	-
16	Capitalized Overhead	(10.177)	(10.177)	-
17				
18	**Depreciation and Amortization**			
19	Amortization of Deferrals	1.558	1.558	-
20	Depreciation variance on Clean Growth Projects/CPCNs/Exogenous Capital	-	(0.027)	(0.027)
21	CIAC Amortization variance on Clean Growth Projects/CPCNs/Exogenous Capital	-	0.021	0.021
22				
23	**Total Property Taxes**	17.621	17.385	(0.236)
24				
25	**Other Revenues**			
26	EV Carbon Credits	(0.625)	(0.744)	(0.119)
27				
28	**Interest Expense**			
29	Long-term debt interest expense variance	41.794	41.794	(0.000)
30	Interest variance on Clean Growth Projects/CPCNs/Exogenous Capital	-	(0.041)	(0.041)
31	Short-term debt rate variance	2.253	0.964	(1.289)
32	Short-term debt volume variance from long-term debt issue variance	(1.005)	(0.646)	0.359
33	Short-term debt timing variance from long-term debt issue timing	0.793	0.510	(0.283)
34				
35	**Income Tax Expense**			
36	Income tax variance on Clean Growth Projects/CPCNs/Exogenous Capital	-	(0.470)	(0.470)
37	Income tax/CCA rate changes	-	-	-
38	Income tax on taxable flowthrough variances above (excl. Clean Growth Projects/CPCNs/Exogenous Capital)	1.877	5.169	3.292
39				
40	**2022 Ending Deferral Account Balance True-up**			**(9.418)**

FBC provides the following explanations of the 2022 Actual variances shown in Table 12-3 above:

- The favourable variance in revenue of $11.397 million was primarily due to higher than projected residential and wholesale loads resulting largely from weather variations. Favourable variances in residential ($11.641 million), industrial ($0.270 million) and wholesale ($0.201 million) revenue were partially offset by unfavourable variances in commercial ($0.547 million), irrigation ($0.146 million) and lighting ($0.022 million) revenue;

- The increase in power purchase expense of $0.293 million was due to several factors including increased load, increased market purchases, and increased reliance on the BC Hydro PPA. Increased load and PPA purchases were primarily a result of prolonged cold weather at the end of 2022. This increase was partially offset by increased surplus capacity sales under the Capacity and Energy Purchase and Sale Agreement (CEPSA);

- The increase in wheeling costs of $0.568 million was primarily due to increased use of wheeling under BC Hydro's Open Access Transmission Tariff;

- The decrease in water fees of $0.078 million was primarily due to reduced water rental rates compared to forecast;

- The flow-through components of O&M expense were $0.011 million lower than projected, with all items comparable to the projected amounts;

- Actual property tax expense was relatively consistent with the projected amount;

- The flow-through components of other revenue were $0.119 million higher than projected, with the variance in EV Carbon Credit revenue due to approximately 329 carbon credits related to FBC's EV charging stations that were validated by BC-LCFS and monetized in 2022 but were not accounted for in the 2022 Projected amount;

- The variance between the actual (2.58 percent) and projected (4.02 percent) short-term debt interest rates results in an amount to be returned to customers of $1.289 million,[52] shown on Line 31 of the table above. There was no variance in long-term debt interest expense as actuals were as projected. The net variance of $0.076 million to be collected from customers on Lines 32 and 33 of Table 12-3 above is due to the impact of a lower actual short-term interest rate than projected;

- The unfavourable income tax variance of $3.292 million is calculated as 27 percent of the aforementioned variances; and

- The combined favourable variance of $0.517 million related to depreciation, CIAC amortization, interest and tax variances on Clean Growth/CPCN/exogenous capital amounts, shown on Lines 20, 21, 30 and 36, respectively, were derived for 2022 by comparing the actual 2022 cost of service impacts of the EV stations and the UBO, Grand Forks Terminal Station and Corra Linn projects to the amounts forecast for those same projects.

12.5 SUMMARY

FBC is not seeking any exogenous factor treatment in this Application. FBC is also not seeking approval of any new non-rate base deferral accounts but has provided an update on the Flow-through deferral account.

[52] (2.584% - 4.02%) x $89.744 million forecast 2022 short-term debt in Schedule 26 of Annual Review for 2022 Rates Compliance Filing financial schedules.

13. SERVICE QUALITY INDICATORS

13.1 INTRODUCTION AND OVERVIEW

Under the MRP, SQIs are used to monitor the Utility's performance to ensure that any efficiencies and cost reductions do not result in a degradation of the quality of service to customers.

In the MRP Decision and Order G-166-20, the BCUC approved a balanced set of SQIs for FBC, covering safety, responsiveness to customer needs, and reliability. Eight of the SQIs have benchmarks and performance ranges set by a threshold level. Four of the SQIs are for information only and as such do not have benchmarks or performance ranges.

In the subsections below, FBC reports on its 2022 and June 2023 year-to-date performance as measured against the SQI benchmarks and thresholds. In 2022, for the eight SQIs with benchmarks, six met or were better than the benchmark, with the First Contact Resolution better than the threshold and the Telephone Service Factor (Non-Emergency) lower than the threshold. For the four SQIs that are informational only, with the exception of the Average Speed of Answer results being higher due to the same challenges impacting the Telephone Service Factor (Non-Emergency), performance in 2022 for the other three informational metrics generally remains at a level consistent with prior years. In 2023 to date, performance for the metrics with benchmarks are trending towards meeting the benchmark or the threshold.

Consistent with how SQIs were reviewed during the 2014-2019 PBR Plan term,[53] FBC has provided 2022 and year-to-date 2023 SQI results in this annual review.

13.2 REVIEW OF THE PERFORMANCE OF SERVICE QUALITY INDICATORS

For each SQI, Table 13-1 provides a comparison of FBC's 2022 and June year-to-date performance for 2023 to the proposed benchmarks and thresholds approved as part of the MRP. Actual 2022 and June year-to-date results for 2023 are also provided for the four informational SQIs.

Table 13-1: Approved SQIs, Benchmarks and Actual Performance

Performance Measure	Description	Benchmark	Threshold	2022 Results	June 2023 YTD Results
Safety SQIs					
Emergency Response Time	Percent of calls responded to within two hours	>=93%	90.6%	94%	93%
All Injury Frequency Rate (AIFR)	3 year average of lost time injuries plus medical treatment injuries per 200,000 hours worked	<=1.64	2.39	1.42	1.76

[53] MRP Decision page 99: "the Panel determines that the existing approved process for interpreting metric performance is to remain in effect over the term of the MRPs."

Performance Measure	Description	Benchmark	Threshold	2022 Results	June 2023 YTD Results
Responsiveness to Customer Needs SQIs					
First Contact Resolution	Percent of customers who achieved call resolution in one call	>=78%	74%	77%	78%
Billing Index	Measure of customer bills produced meeting performance criteria	<=3.0	5.0	0.14	2.20
Meter Reading Accuracy	Number of scheduled meters that were read	>=98%	96%	99%	99%
Telephone Service Factor (Non-Emergency)	Percent of non-emergency calls answered within 30 seconds or less	>=70%	68%	65%	72%
Customer Satisfaction Index	Informational indicator - measures overall customer satisfaction	-	-	8.4	8.5
Average Speed of Answer	Informational indicator – the amount of time it takes to answer a call (seconds)	-	-	98	60
Reliability SQIs					
System Average Interruption Duration Index (SAIDI) – Normalized	Annual SAIDI (average of cumulative customer outage time)	3.22[54]	4.52	2.42	3.21
System Average Interruption Frequency Index (SAIFI) - Normalized	Annual SAIFI (average customer outage)	1.57	2.19	1.52	1.48
Generator Forced Outage Rate	Informational indicator – Percent of time a generating unit is removed from service due to component failure or other events.	-	-	0.50%	0.65%
Interconnection Utilization	Informational indicator – percent of time that an interconnection point was available and providing electrical service to wholesale customers.	-	-	99.94%	99.98%

In the following sections, FBC reviews each SQI's year-to-date individual performance in 2022 and 2023. Discussion is also provided for the informational SQIs.

[54] Benchmarks and thresholds for SAIDI and SAIFI were approved in the FBC Annual Review for 2020 and 2021 Rates Decision and Order G-42-21.

13.2.1 Safety Service Quality Indicators

13.2.1.1 Emergency Response Time

Emergency Response Time is the time elapsed from the initial identification of a loss of electrical power (via a customer call or internal notification) to the arrival of FBC personnel on site at the trouble location. This metric provides ongoing information to assess FBC crew sizes and crew locations in response to system trouble. The target measures the percentage of emergency calls responded to within two hours. The measure is calculated as follows:

$$\frac{\text{Number of emergency calls responded to within two hours}}{\text{Total number of emergency calls in the year}}$$

There are many variables affecting the response time, including time of day (i.e., during business hours or after business hours), number and type of events (i.e., widespread outages), available resources, location (i.e., travel times and traffic congestion) and weather conditions.

The 2022 result was 94 percent which was better than the benchmark. The June 2023 year-to-date performance is 93 percent, which meets the benchmark.

For comparison, the Company's annual results under the 2014-2019 PBR Plan, the 2020, 2021, and 2022 results and the June 2023 year-to-date emergency response time results are provided below. While the results have been relatively consistent, variables such as the location and severity of outage and the number of trouble calls contribute to the observed volatility in the annual performance for this metric.

Table 13-2: Historical Emergency Response Time

Description	2014	2015	2016	2017	2018	2019	2020	2021	2022	June 2023 YTD
Results	91%	92%	97%	93%	94%	92%	92%	93%	94%	93%
Benchmark	93%									
Threshold	90.6%									

13.2.1.2 All Injury Frequency Rate

The All Injury Frequency Rate (AIFR) is an employee safety performance indicator based on injuries per 200,000 hours worked, with injuries defined as lost time injuries (i.e., one or more days missed from work) and medical treatments (i.e., medical treatment was given or prescribed). The annual performance for this metric is calculated as:

$$\frac{\text{Number of Employee Injuries x 200,000 hours}}{\text{Total Exposure Hours Worked}}$$

For the purpose of this SQI, the measurement of performance is based on the three-year rolling average of the annual results.

The 2022 (three-year rolling average) result was 1.42 which was better than the benchmark of 1.64. The 2022 annual AIFR was 2.60 which reflected 4 Medical Treatments and 8 Lost Time Injuries. The increase in AIFR was particularly prevalent in Q4 2022, after a sudden change in winter conditions led to a notable spike in slips, trips, and falls resulting in more serious injuries. FBC responded to this by issuing an immediate safety alert (Safely Navigating Winter Conditions) to all field employees, which was also reviewed at all safety meetings, and providing access to traction aids throughout Operations.

The June 2023 year-to-date performance (three-year rolling average) result is 1.76 which is better than the threshold. The June 2023 year-to-date performance (annual) is 2.54 and reflects 3 Medical Treatments and 3 Lost Time Injuries. Thus far in 2023, FBC continues to see an increase in total minor preventable injuries, predominately those sustained while performing activities involving repetitive work and/or awkward positioning. FBC has responded to this by engaging its Ergonomist and Injury Prevention Specialist to provide more education and treatment throughout the Company. FBC also hired an Injury Management Specialist to provide proactive educational sessions, as well as customized Recover at Work plans for employees. In addition, FBC has implemented customized ergonomics courses for some of the higher risk areas.

Strengthening the safety culture continues to be a key driver for FBC, building on the commitment to learn from safety events, identify safety hazards, assess risk and continually improve the safety management system through the implementation and sustainment of robust safety defences and controls.

For comparison, the Company's results under the 2014 to 2019 PBR Plan, the 2020, 2021 and 2022 results and the June year-to-date AIFR results are provided below.

Table 13-3: Historical All Injury Frequency Rate Results

Description	2014	2015	2016	2017	2018	2019	2020	2021	2022	June 2023 YTD
Annual Results	3.21	1.54	1.15	1.13	1.56	0.46	0.66	0.89	2.60	2.54
Three year rolling average	2.58	2.52	1.97	1.27	1.28	1.06	0.87	0.67	1.42	1.76
Benchmark	1.64									
Threshold	2.39									

13.2.2 Responsiveness to Customer Needs Service Quality Indicators

13.2.2.1 First Contact Resolution

First Contact Resolution (FCR) measures the percentage of customers who receive resolution to their issue in one contact with FBC. The Company determines the FCR results using a customer survey, tracking the number of customers who responded that their issue was resolved in the first contact with the Company. The FCR rate is impacted by factors such as the quality and

effectiveness of the Company's coaching and training programs and the composition of the different call drivers.

The 2022 result was 77 percent which was better than the threshold of 74 percent. The reduction in FCR for 2022 as compared to previous years, as shown in Table 13-4 below, is largely attributable to the increased volume of high bill inquiries. Depending on the nature of the high bill, there may be a need for customers to follow up on their bill, resulting in more than one contact to resolve their concerns. As well, high bill calls can require longer-term payment arrangements which at times may require changes, leading to customers connecting with FBC multiple times for the same reason. The June 2023 year-to-date performance is 78 percent which meets the benchmark.

For comparison, the Company's results under the 2014 to 2019 PBR Plan, the 2020, 2021 and 2022 results and the June 2023 year-to-date results are provided below.

Table 13-4: Historical First Contact Resolution Levels

Description	2014	2015	2016	2017	2018	2019	2020	2021	2022	June 2023 YTD
Annual Results	73%	76%	79%	80%	82%	82%	82%	82%	77%	78%
Benchmark	78%									
Threshold	72%						74%			

13.2.2.2 Billing Index

The Billing Index indicator tracks the effectiveness of the Company's billing system by measuring the percentage of customer bills produced meeting performance criteria. The Billing Index is a composite index with three components:

- Billing completion (percent of accounts billed within two days of the billing due date);
- Billing timeliness (percent of invoices delivered to Canada Post within two days of file creation); and
- Billing accuracy (percent of bills without a production issue based on input data).

The objective is to achieve a score of five or less.

The Billing Index is impacted by factors such as the performance of the Company's billing system, weather variability, which can cause a high volume of billing checks and estimation issues, and mail delivery by Canada Post.

The 2022 result was 0.14 which was better than the benchmark of 3.0. No significant billing issues occurred in 2022. The June 2023 year-to-date result of 2.20 is attributable to a technical issue experienced in February which resulted in a timing delay between the creation of the bills and those bills being sent to the print vendor. This technical issue has been corrected.

The 2022 Billing Index sub-measures calculation is as follows.

Table 13-5: Calculation of 2022 Billing Index

Billing sub-measure	Percent Achieved (PA)	Formula		Result
Billing Accuracy (Percent of bills without a Production Issue, based on input data); Target: 99.9%	100.00%	If (PA≥99.9%,5000*(1 - PA),100*(1.05-PA))	=5000*(1-100%)	0.00
Billing Timeliness (Percent of invoices delivered to Canada Post within 2 days of file creation); Target: 95%	100.00%	(100%-PA)*100	=(100%-100%)*100	0.00
Billing Completion (Percent of accounts billed within 2 days of the billing due date); Target: 95%	99.57%	(100%-PA)*100	=(100%-99.57%)*100	0.43
Billing Service Quality Indicator; Target < 3.0		(Accuracy PA+Timeliness PA+Completion PA)/3	=(0.+0+0.43) /3	0.14

For comparison, the Company's results under the 2014 to 2019 PBR Plan, the 2020, 2021 and 2022 results and the June 2023 year-to-date results are provided below.

Table 13-6: Historical Billing Index Results

Description	2014	2015	2016	2017	2018	2019	2020	2021	2022	June 2023 YTD
Annual Results	2.34	0.39	0.57	0.15	0.29	1.96	0.13	0.12	0.14	2.20
Benchmark	5.0						3.0			
Threshold	5.0									

13.2.2.3 Meter Reading Accuracy

This SQI compares the number of meters that are read to those scheduled to be read. Providing accurate and timely meter reads for customers is a key driver for the Company and its customers. The results are calculated as:

$$\frac{\text{Number of scheduled meters read}}{\text{Number of scheduled meters for reading}}$$

The 2022 result was 99 percent, which was better than the benchmark of 98 percent. The June 2023 year-to-date result is 99 percent, which is better than the benchmark.

For comparison, the Company's results under the 2014 to 2019 PBR Plan, the 2020, 2021 and 2022 results and the June 2023 year-to-date results are provided below.

Table 13-7: Historical Meter Reading Accuracy Results

Description	2014	2015	2016	2017	2018	2019	2020	2021	2022	June 2023 YTD
Annual Results	98%	96%	99%	99%	99%	99%	99%	99%	99%	99%
Benchmark	97%						98%			
Threshold	94%						96%			

13.2.2.4 Telephone Service Factor (Non-Emergency)

The Telephone Service Factor (Non-Emergency) measures the percentage of non-emergency calls that are answered in 30 seconds. It is calculated as:

$$\frac{\text{Number of non-emergency calls answered within 30 seconds}}{\text{Number of non-emergency calls received}}$$

The TSF is a measure of how well the Company can balance costs and service levels with the overall objective to maintain a consistent TSF level. This ensures the Company is staying within appropriate cost levels and maintaining adequate service for its customers. The principal factors influencing the TSF results include volume and type of inbound calls received and the resources available to answer those calls. Staffing is matched to the expected call volume based on historical data in order to reach the service level benchmark desired. Other factors that can influence the TSF are billing system related issues and weather patterns that may generate high numbers of billing related queries and the complexity of the calls.

The 2022 result was 65 percent, which was lower than the threshold. The June 2023 year-to-date performance is 72 percent, which is better than the benchmark.

FBC experienced several challenging circumstances in 2022 that contributed to the year-end performance being below the threshold. These challenges included higher than expected attrition being experienced in the contact centre, compounded by an increased amount of high bill inquiries in the first and fourth quarters. Each of these is described further below.

Customer Service is experiencing higher than expected levels of attrition, having lost approximately 40 percent of its Customer Service Representatives in 2022, compared to 20 percent in 2021.[55] Exits in 2021 occurred during the third and fourth quarters, resulting in fewer and less experienced employees prepared to support call volumes at the start of 2022. Additionally, 2022 exits were spread throughout 2022 with the majority in the first and fourth quarters. To mitigate the impact of this attrition, FBC accelerated the timing of planned new hire

[55] On average, FBC has approximately 20 customer service representatives, and 8 left the organization in 2022 and 4 in 2021. This compares to typical annual attrition in the range of 1-2 customer service representatives from the organization.

classes as well as the size of new hire classes in 2021, 2022 and 2023. While some success was achieved, FBC continued to face challenges recruiting and retaining newly hired contact centre employees in 2022. In addition, it takes approximately 12 months for new employees to be proficient and fully trained to support all customer inquiries and calls, and as such, average call handle times remain higher than normal while a greater portion of employees gain this experience.

High bill inquiries are expected in the first quarter of the year and planned for with staffing levels and schedules adjusted, new hire classes timed accordingly, and refresher training offered to those employees who may need it. However, the colder temperatures resulted in a volume of high bill inquiries that was greater than anticipated and lasted longer than typical. This particular call type is often longer in duration and may also result in follow-up work and investigation. Compounded by attrition, there were fewer and less experienced employees prepared to support these types of calls, resulting in overall longer average wait times and a lower percentage of calls answered within 30 seconds or less.

The additional hiring and training classes in 2023 have proven to be successful, with year-to-date performance better than the benchmark. Additionally, the customer service index has remained high throughout 2022 and 2023 year-to-date, indicating that the focus on first contact resolution continues to result in an overall high quality of service being experienced by customers.

For comparison, the Company's results under the 2014 to 2019 PBR Plan, the 2020, 2021 and 2022 results and the June 2023 year-to-date results are provided below. As discussed in the Annual Review for 2015 Rates, the 2014 result was negatively impacted by events such as the first verified meter readings occurring after the IBEW labour disruption ended in December 2013, introduction of the Residential Conservation Rate, and the integration of the City of Kelowna customers.

Table 13-8: Historical TSF (Non-Emergency) Results

Description	2014	2015	2016	2017	2018	2019	2020	2021	2022	June 2023 YTD
Annual Results	48%	71%	70%	70%	72%	70%	70%	70%	65%	72%
Benchmark	70%									
Threshold	68%									

13.2.2.5 Customer Satisfaction Index

The Customer Satisfaction Index (CSI) is an informational indicator that measures overall customer satisfaction with the Company. The index reflects customer feedback about important service touch points including the contact centre, perceived accuracy of meter reading, energy conservation information and field services. The index includes feedback from both residential and commercial customers. The survey is conducted quarterly, and results are presented as a score out of 10.

The CSI survey investigates service quality as well as customer attitudes that are often influenced by factors outside the Company's control. Important examples include storm-related unplanned outages and media coverage.

The annual CSI score for 2022 was 8.4, consistent with 2021. There were no statistically significant shifts from 2021 to 2022 in the five measures that make up the overall customer satisfaction score. The score for the accuracy of meter reading metric increased from 8.2 in 2021 to 8.3 in 2022. The score for the satisfaction with energy conservation information metric decreased from 7.5 in 2021 to 7.4 in 2022. In addition, the scores for overall satisfaction, satisfaction with the contact centre and field services metrics remained static at 8.4, 8.4, and 9.0 in 2022, respectively.

The score for 2023 year-to-date is 8.5, slightly higher than the annual score recorded for 2022. Of the five measures that make up the overall customer satisfaction score, the results for June 2023 year-to-date were higher in three areas and static in two when compared to the annual 2022 scores. The scores for the satisfaction with energy conservation, contact centre, and field services metrics increased from 7.4 to 7.5, 8.4 to 8.5, and 9.0 to 9.2, respectively. The scores for the overall satisfaction and satisfaction with the accuracy of meter reading metrics remained static at 8.4 and 8.3, respectively, from results achieved in 2022. None of these changes are statistically significant.

For comparison, the Company's results under the 2014 to 2019 PBR Plan, the 2020, 2021 and 2022 results and the June 2023 year-to-date results are provided below.

Table 13-9: Historical Customer Satisfaction Results

Description	2014	2015	2016	2017	2018	2019	2020	2021	2022	June 2023 YTD
Annual Results	8.1	8.1	8.2	8.2	8.3	8.5	8.5	8.4	8.4	8.5
Benchmark	n/a									
Threshold	n/a									

13.2.2.6 Average Speed of Answer

The Average Speed of Answer (ASA) is an informational indicator that measures the amount of time it takes for a customer service representative to answer a customer's call (seconds).

The 2022 result was 98 seconds, and the June 2023 year-to-date performance is 60 seconds.

2022 performance reflects the challenging circumstances described above for the Telephone Service Factor (Non-Emergency). Recovery of the ASA commenced in March 2023 with monthly ASA performance returning to typical levels of approximately 1 minute. This is expected to continue through the remainder of the year.

For comparison, the Company's results under the 2014 to 2019 PBR Plan, the 2020, 2021 and 2022 results and the June 2023 year-to-date results are provided below.[56]

Table 13-10: Average Speed of Answer

Description	2014	2015	2016	2017	2018	2019	2020	2021	2022	June 2023 YTD
Annual Results	226	49	48	49	49	49	71	65	98	60
Benchmark	n/a									
Threshold	n/a									

13.2.3 Reliability Service Quality Indicators

FBC measures transmission and distribution system reliability according to the Institute of Electrical and Electronics Engineers (IEEE) method of normalizing reliability statistics by excluding "major events". Major events are identified as those that cause outages exceeding a threshold number of customer-hours. Threshold values are calculated by applying a statistical method called the "2.5 Beta" adjustment to historical reliability data. Any single outage event that exceeds the threshold value is excluded from the reliability data. Excluding major events allows them to be studied separately and reveals trends in daily operations that would be hidden or skewed if they were included in the data set. Major event days in the FBC service territory have been caused by mudslides, wind or snow storms, and wildfires.

Reported outages included in these measures are of one minute or longer in duration, which is consistent with the Canadian Electricity Association (CEA) standard for reporting.

13.2.3.1 System Average Interruption Duration Index (SAIDI) – Normalized

SAIDI is the amount of time the average customer's power is off during the year (i.e., the total amount of time the average customer's clock would lose during a year), after adjusting for the impact of major events as described above, and is calculated as follows:

$$\frac{\text{Total Customer Hours of Interruption}}{\text{Total Number of Customers Served}}$$

Customer Hours of Interruption related to a power outage are calculated by multiplying the number of customers affected by the outage by the duration of the outage.

For the purpose of this SQI, the measurement of performance is based on the annual results.

The 2022 result was 2.42 which was better than the benchmark of 3.22. The June 2023 year-to-date performance is 3.21 which is better than the benchmark. The 2022 results improved

[56] ASA in 2014 is higher than other years due to the impact of the six months of job action that took place in Q3 and Q4 of 2013. This job action resulted in a higher number of bill estimates, which led to a higher volume of customer inquiries in 2014 as bill adjustments were made reflecting actual meter reads.

compared to 2021 due to the absence of multiple external factors (i.e., fires, storms, collapse of crane incident in Kelowna in 2021)[57] which negatively impacted the 2021 SAIDI results.

There were no Major Event Days that met the threshold for normalization in 2022, and one Major Event Day in 2023 year-to-date. On May 21, 2023, a windstorm impacted the Kootenay region (centered in Salmo) resulting in outages to over 13,500 customers for a total of just under 46,200 customer hours lost.

For comparison, the Company's results under the 2014 to 2019 PBR Plan, the 2020, 2021 and 2022 results and the June 2023 year-to-date results are provided below. From 2014 to 2019, the benchmark and the threshold reflect the values established under the PBR Plan using three-year rolling average results. Starting in 2020, the benchmark and threshold reflect the values approved by the BCUC for the MRP term.[58]

Table 13-11: Historical SAIDI Results

Description	2014	2015	2016	2017	2018	2019	2020	2021	2022	June 2023 YTD
Annual normalized results	2.32	2.13	2.10	4.05	3.15	2.45	3.17	4.27	2.42	3.21
Benchmark	2.22						3.22			
Threshold	2.62						4.52			

13.2.3.2 System Average Interruption Frequency Index (SAIFI) – Normalized

SAIFI is the average number of interruptions per customer served per year (i.e., the number of times the average customer would have to reset their clock during the year), after adjusting for the impact of major events as described above, and is calculated as follows:

$$\frac{\text{Total Number of Customer Interruptions}}{\text{Total Number of Customers Served}}$$

The Number of Customer Interruptions related to a power outage is the number of customers affected by the outage.

For the purpose of this SQI, the measurement of performance is based on the annual results.

The 2022 result was 1.52 which was better than the benchmark, and the June 2023 year-to-date performance is 1.48 which is also better than the benchmark. The 2022 SAIFI results improved compared to 2021 due to the absence of the same multiple external factors (i.e., fires, storms and collapse of crane incident in Kelowna in 2021) discussed in the SAIDI section above.

[57] Refer to the FBC Annual Review for 2023 Rates, pages 140-141 for further details.
[58] The benchmark and threshold for SAIDI were approved in the FBC Annual Review for 2020 and 2021 Rates Decision and Order G-42-21.

For comparison, the Company's results under the 2014 to 2019 PBR Plan, the 2020, 2021 and 2022 results and the June 2023 year-to-date results are provided below. From 2014 to 2019, the benchmark and the threshold reflect the values established under the PBR Plan using three-year rolling average results. Starting in 2020, the benchmark and threshold reflect the values approved by the BCUC for the MRP term.[59]

Table 13-12: Historical SAIFI Results

Description	2014	2015	2016	2017	2018	2019	2020	2021	2022	June 2023 YTD
Annual normalized results	1.64	1.56	1.34	1.78	1.73	1.21	1.64	2.08	1.52	1.48
Benchmark	1.64						1.57			
Threshold	2.50						2.19			

13.2.3.3 Generator Forced Outage Rate

Generator Forced Outage Rate (GFOR), an informational indicator, is a measure of the percentage of time in one year that the generating units experienced forced outages compared to the amount of time they could have operated without a forced outage. A forced outage means the removal of a generating unit from service due to the occurrence of a component failure or other event, making it unavailable to produce power due to the unexpected breakdown. The GFOR is defined by the CEA as follows:

$$\frac{\text{Total Forced Outage Time}}{\text{Total Forced Outage Time + Total Operating Time}} \text{ X } 100$$

The 2022 result for GFOR was 0.50 percent. The June 2023 year-to-date performance is 0.65 percent.

For comparison, the Company's results under the 2014 to 2019 PBR Plan, the 2020, 2021 and 2022 results and the June 2023 year-to-date results are provided below.

Table 13-13: Historical Generator Forced Outages

	2014	2015	2016	2017	2018	2019	2020	2021	2022	June 2023 YTD
FBC	1.7%	0.1%	0.8%	0.6%	0.4%	0.1%	1.3%	0.2%	0.5%	0.65%
CEA	6.3%	6.2%	6.2%	6.2%	6.7%	4.9%	4.6%	5.0%	TBD	

[59] The benchmark and threshold for SAIFI were approved in the FBC Annual Review for 2020 and 2021 Rates Decision and Order G-42-21.

13.2.3.4 Interconnection Utilization

Interconnection Utilization, an informational indicator, is a measurement of the time that an interconnection point was available and providing electrical service to the municipal wholesale customers (City of Penticton, City of Summerland, City of Grand Forks and City of Nelson). There are 12 points of interconnection combined between the four customers.

The Interconnection Utilization metric for the interconnection points listed is calculated as follows:

$$\frac{\text{Total Operating Hours}}{\text{Total Operating Hours + Total Outage Time}}$$

The 2022 result of 99.94 percent and June 2023 year-to-date result of 99.98 percent are generally consistent with prior years' results. There were no notable major events in 2022 that impacted the interconnection utilization performance. For comparison, the Company's results under the 2014 to 2019 PBR Plan, the 2020, 2021 and 2022 results and the June 2023 year-to-date results are provided below.

Table 13-14: Interconnection Utilization

Description	2014	2015	2016	2017	2018	2019	2020	2021	2022	June 2023 YTD
Interconnection Utilization	99.99%	99.94%	99.99%	99.95%	99.96%	99.98%	99.89%	99.90%	99.94%	99.98%
Benchmark	n/a									
Threshold	n/a									

13.3 SUMMARY

In summary, FBC's 2022 and June 2023 year-to-date SQI results indicate that the Company's overall performance is representative of a high level of service quality. In 2022, for the eight SQIs with benchmarks, six met or were better than the benchmark with one, First Contact Resolution, better than the threshold and the Telephone Service Factor (Non-Emergency) lower than the threshold. For the four SQIs that are informational only, with the exception of the Average Speed of Answer results being higher, performance in 2022 for the other three informational metrics generally remains at a level consistent with prior years.

Appendix A

LOAD FORECAST SUPPLEMENTARY INFORMATION

Table A1-1: Consumer Price Index (CPI)

Reference period	
	2002=100
July 2021	136.7
August 2021	137.0
September 2021	137.2
October 2021	137.9
November 2021	138.1
December 2021	138.0
January 2022	139.4
February 2022	140.4
March 2022	143.0
April 2022	144.2
May 2022	146.1
June 2022	146.5
July 2022	147.6
August 2022	147.0
September 2022	147.8
October 2022	148.6
November 2022	148.1
December 2022	147.1
January 2023	148.1
February 2023	149.1
March 2023	149.7
April 2023	150.4
May 2023	151.0
June 2023	151.6

Table A1-2: Average Weekly Earnings (AWE)

Reference period	
	Dollars
July 2021	1,143.76[B]
August 2021	1,143.96[B]
September 2021	1,142.37[B]
October 2021	1,140.94[B]
November 2021	1,129.51[B]
December 2021	1,132.93[B]
January 2022	1,155.32[B]
February 2022	1,153.57[B]
March 2022	1,161.00[B]
April 2022	1,164.51[B]
May 2022	1,159.89[B]
June 2022	1,167.14[B]
July 2022	1,162.26[B]
August 2022	1,171.52[B]
September 2022	1,171.94[B]
October 2022	1,174.29[B]
November 2022	1,176.97[B]
December 2022	1,153.31[B]
January 2023	1,180.04[B]
February 2023	1,175.83[B]
March 2023	1,191.20[B]
April 2023	1,199.14[B]

Table A1-3: British Columbia Three-Year Outlook 2023

Key Economic Indicators: British Columbia, 2022–25
(forecast completed February 6, 2023)

	2023Q1	2023Q2	2023Q3	2023Q4	2024Q1	2024Q2	2024Q3	2024Q4	2025Q1	2025Q2	2025Q3	2025Q4	2022	2023	2024	2025
GDP at market prices ($ millions)	391,736	395,415	399,177	403,736	406,355	410,776	415,451	420,228	424,501	428,452	432,006	435,380	387,452	397,516	413,202	430,085
	0.8	*0.9*	*1.0*	*1.1*	*0.6*	*1.1*	*1.1*	*1.1*	*1.0*	*0.9*	*0.8*	*0.8*	*10.5*	*2.6*	*3.9*	*4.1*
GDP at market prices (2012 $ millions)	288,445	288,783	289,747	291,630	293,450	295,974	298,578	301,260	303,505	305,509	307,230	308,858	288,561	289,651	297,315	306,276
	-0.4	*0.1*	*0.3*	*0.6*	*0.6*	*0.9*	*0.9*	*0.9*	*0.7*	*0.7*	*0.6*	*0.5*	*2.3*	*0.4*	*2.6*	*3.0*
GDP at basic prices (2012 $ millions)	268,952	269,263	270,150	271,927	273,661	276,038	278,453	280,981	283,105	284,983	286,596	288,138	268,886	270,073	277,283	285,705
	-0.4	*0.1*	*0.3*	*0.7*	*0.6*	*0.9*	*0.9*	*0.9*	*0.8*	*0.7*	*0.6*	*0.5*	*2.4*	*0.4*	*2.7*	*3.0*
Consumer price index (2002 = 1.000)	1.494	1.511	1.518	1.525	1.537	1.547	1.553	1.559	1.567	1.578	1.584	1.590	1.455	1.512	1.549	1.580
	1.0	*1.1*	*0.5*	*0.5*	*0.8*	*0.6*	*0.4*	*0.4*	*0.6*	*0.7*	*0.4*	*0.4*	*6.9*	*3.9*	*2.4*	*2.0*
Implicit price deflator—GDP at market prices	1.358	1.369	1.378	1.384	1.385	1.388	1.391	1.395	1.399	1.402	1.406	1.410	1.343	1.372	1.390	1.404
(2012 = 1.000)	*1.1*	*0.8*	*0.6*	*0.5*	*0.0*	*0.2*	*0.3*	*0.2*	*0.3*	*0.3*	*0.3*	*0.2*	*8.1*	*2.2*	*1.3*	*1.0*
Wages and salary per employee ($ 000s)	62.6	63.0	63.4	63.9	64.3	64.7	65.2	65.5	65.8	66.2	66.6	66.9	61.3	63.2	64.9	66.4
	1.4	*0.6*	*0.6*	*0.8*	*0.7*	*0.6*	*0.6*	*0.6*	*0.4*	*0.6*	*0.6*	*0.6*	*7.5*	*3.2*	*2.7*	*2.2*
Primary household income ($ millions)	271,333	273,731	277,762	281,397	284,854	288,183	291,553	294,696	297,304	300,218	303,091	306,018	263,680	276,056	289,821	301,658
	1.0	*0.9*	*1.5*	*1.3*	*1.2*	*1.2*	*1.2*	*1.1*	*0.9*	*1.0*	*1.0*	*1.0*	*9.3*	*4.7*	*5.0*	*4.1*
Household disposable income ($ millions)	238,251	238,085	241,327	244,400	246,131	248,862	251,726	254,524	256,290	258,790	261,242	263,730	230,486	240,516	250,311	260,013
	0.8	*-0.1*	*1.4*	*1.3*	*0.7*	*1.1*	*1.2*	*1.1*	*0.7*	*1.0*	*0.9*	*1.0*	*6.4*	*4.4*	*4.1*	*3.9*
Household net savings rate (per cent)	6.5	5.4	5.4	5.3	5.0	4.9	4.8	4.8	4.7	4.6	4.7	4.7	5.1	5.6	4.9	4.7
Population (000s)	5,395	5,422	5,447	5,472	5,496	5,519	5,542	5,564	5,586	5,608	5,631	5,652	5,303	5,434	5,530	5,619
	0.5	*0.5*	*0.5*	*0.5*	*0.4*	*0.4*	*0.4*	*0.4*	*0.4*	*0.4*	*0.4*	*0.4*	*2.1*	*2.5*	*1.8*	*1.6*
Employment (000s)	2,767	2,766	2,781	2,794	2,804	2,816	2,827	2,837	2,847	2,857	2,866	2,875	2,748	2,777	2,821	2,861
	0.3	*0.0*	*0.6*	*0.4*	*0.4*	*0.4*	*0.4*	*0.4*	*0.3*	*0.3*	*0.3*	*0.3*	*3.1*	*1.0*	*1.6*	*1.4*
Labour force (000s)	2,910	2,916	2,929	2,939	2,949	2,959	2,969	2,979	2,989	2,999	3,008	3,017	2,880	2,923	2,964	3,003
	0.9	*0.2*	*0.4*	*0.4*	*0.3*	*0.3*	*0.4*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*1.0*	*1.5*	*1.4*	*1.3*
Labour force participation rate (per cent)	64.3	64.1	64.1	64.0	64.0	63.9	63.9	63.8	63.8	63.7	63.7	63.6	64.9	64.1	63.9	63.7
Unemployment rate (per cent)	4.9	5.1	5.0	4.9	4.9	4.8	4.8	4.8	4.8	4.7	4.7	4.7	4.6	5.0	4.8	4.7
Retail sales ($ millions)	100,889	101,567	102,870	104,222	105,539	106,986	108,360	109,565	110,577	111,794	112,829	113,854	101,049	102,387	107,613	112,263
	0.0	*0.7*	*1.3*	*1.3*	*1.3*	*1.4*	*1.3*	*1.1*	*0.9*	*1.1*	*0.9*	*0.9*	*2.5*	*1.3*	*5.1*	*4.3*
Housing starts (units, 000s)	39,451	38,118	38,500	40,000	42,000	43,584	43,850	43,838	43,692	43,528	43,340	43,127	46,721	39,017	43,318	43,422
	-23.3	*-3.4*	*1.0*	*3.9*	*5.0*	*3.8*	*0.6*	*0.0*	*-0.3*	*-0.4*	*-0.4*	*-0.5*	*-1.9*	*-16.5*	*11.0*	*0.2*
Net interprovincial migration (000s)	15.2	17.7	16.3	16.8	17.0	17.3	17.5	17.8	18.0	18.3	18.5	18.8	12	16.5	17.4	18.4
Net international migration (000s)	89.7	85.5	81.8	78.9	76.5	74.6	73.1	72.0	72.3	71.6	71.0	70.5	118.4	84.0	74.1	71.3

Shaded area represents forecast data, *italics indicate percentage change*.
All data are in millions of dollars, seasonally adjusted at annual rates, unless otherwise specified.
For each indicator, the first line is the level and the second line is the percentage change from the previous period.
Sources: The Conference Board of Canada; Statistics Canada; CMHC Housing Time Series Database.

Note: Table above is from the Conference Board of Canada, British Columbia Three-Year Outlook, March 31, 2023.

Appendix A2

Load Forecast Tables

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1. INTRODUCTION

This appendix provides the historical and forecast load data used in Section 3 of the Application. The tables in Section 2 of this appendix show 10 years of historical data and the before-savings and after-savings forecast for 2023S and 2024F. Section 3 shows the customer forecast data while Section 4 presents the residential UPC data. The tables in Section 5 show the load forecast. Table 5.3 shows the DSM that was deducted from the before-savings forecast to provide the after-savings forecast for 2024F. Tables 6.1 and 6.2 show the variance of the customer accounts and forecasts from 2017 to 2022 when compared to the actuals. Table 6.3 shows the annual growth of customer and load that FBC has experienced since 2017. Tables 6.4 and 6.5 show the Residential UPC and Winter peak variances from forecast from 2020 to 2022. Finally, Table 6.6 shows the system load factor from the years 2017 to 2022 and the forecast load factor for 2023S and 2024F.

The tables in this appendix reflect the acquisition by FBC of the assets and customers of the City of Kelowna electric utility effective March 31, 2013. The acquisition resulted in an increase in direct customers to FBC and a re-distribution of load from wholesale to other rate classes in 2013 and 2014.

2. MONTHLY LOAD FORECAST

Forecast loads are shown:

- before-savings – the load before DSM and includes Normalized loads to December 2022.
- after-savings – the load after DSM and includes Normalized loads to December 2022.

2.1 GROSS LOAD (MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Historic Loads													
2013	372,939	327,919	300,296	255,888	249,987	235,093	291,183	274,786	241,239	266,317	303,923	380,406	3,499,975
2014	363,245	306,420	303,949	253,146	241,945	242,396	285,626	270,799	229,532	256,624	301,612	380,684	3,435,977
2015	364,636	317,325	299,476	250,366	249,815	247,921	287,307	276,774	233,611	256,959	300,534	361,093	3,445,816
2016	362,417	311,090	292,322	268,567	248,286	243,400	287,329	280,865	234,850	266,011	328,783	352,683	3,476,603
2017	364,284	298,155	307,568	263,749	249,610	251,126	300,242	289,240	246,675	265,495	324,809	356,765	3,517,718
2018	373,759	312,050	306,251	264,157	273,363	256,750	308,108	296,176	231,268	262,444	302,321	372,719	3,559,367
2019	371,601	294,208	316,259	261,193	267,746	257,893	295,882	292,659	260,751	291,966	314,389	370,267	3,594,813
2020	380,978	331,422	304,284	246,809	239,849	247,702	308,135	302,775	260,553	282,819	332,127	373,313	3,610,765
2021	379,923	340,308	320,380	275,424	255,599	264,059	313,426	294,626	255,445	284,819	333,861	374,965	3,692,835
2022	395,393	344,739	328,117	275,896	259,774	274,145	317,727	309,709	265,171	280,605	337,000	396,554	3,784,830
Before-Savings													
2023S	393,099	343,506	322,822	275,878	267,544	279,101	319,086	308,550	269,588	290,246	343,143	391,122	3,803,684
2024F	395,405	345,601	324,885	277,934	269,596	281,241	321,367	310,778	271,994	292,344	345,298	393,394	3,829,838
After-Savings													
2023S	390,501	340,929	320,309	273,448	265,202	276,815	316,824	306,260	267,245	287,810	340,630	388,565	3,774,539
2024F	390,223	340,479	319,905	273,132	264,983	276,752	316,937	306,307	267,435	287,618	340,441	388,467	3,772,679

2.2 NET LOAD (MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Historic Loads													
2013	337,728	297,641	276,667	237,842	233,199	219,696	268,867	254,751	225,078	247,419	279,078	343,897	3,221,865
2014	329,517	279,546	279,656	235,365	226,070	226,002	263,980	251,199	214,732	238,897	276,987	343,940	3,165,892
2015	330,474	288,500	275,700	232,842	232,855	230,716	265,292	256,237	218,219	239,080	275,925	327,535	3,173,373
2016	328,972	283,576	269,823	248,799	231,696	226,952	265,539	259,978	219,469	247,136	300,036	320,866	3,202,843
2017	330,163	272,433	282,574	244,425	232,665	233,492	276,339	266,935	229,621	246,479	296,394	323,921	3,235,440
2018	338,459	284,446	281,783	245,037	253,552	238,619	283,364	273,179	216,362	244,085	277,755	337,598	3,274,238
2019	336,960	269,648	290,510	242,633	248,852	239,769	273,123	270,359	242,250	269,764	288,203	335,853	3,307,924
2020	345,128	301,193	280,588	230,312	224,658	231,093	283,880	279,297	242,295	262,137	303,482	338,771	3,322,834
2021	344,200	308,531	294,270	255,141	238,455	245,309	288,355	272,273	237,823	263,831	304,896	340,091	3,393,175
2022	356,904	312,144	300,781	255,512	242,069	254,001	291,969	285,142	246,240	260,155	307,481	357,859	3,470,257
Before-Savings													
2023S	356,862	312,701	297,618	256,528	249,790	259,327	294,420	285,377	251,055	269,568	314,129	355,218	3,502,592
2024F	358,989	314,632	299,533	258,433	251,695	261,304	296,522	287,433	253,266	271,513	316,120	357,317	3,526,758
After-Savings													
2023S	354,461	310,320	295,296	254,283	247,626	257,215	292,330	283,261	248,891	267,317	311,807	352,855	3,475,662
2024F	354,202	309,899	294,931	253,996	247,433	257,156	292,429	283,302	249,053	267,146	311,631	352,765	3,473,943

2.3 RESIDENTIAL (MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Historical Normalized Actuals													
2013	145,263	115,730	114,637	112,100	90,869	85,319	120,666	100,397	73,591	97,867	124,661	171,845	1,352,945
2014	147,191	120,724	129,852	84,813	80,792	77,673	105,443	102,753	73,260	95,314	119,531	159,107	1,296,452
2015	150,230	122,084	120,304	91,957	76,652	84,441	110,145	97,235	73,384	99,324	125,839	146,556	1,298,150
2016	147,429	121,286	113,080	99,963	91,648	85,702	101,212	96,335	77,431	96,417	129,741	135,335	1,295,580
2017	145,663	112,986	118,857	102,166	94,155	86,021	106,392	95,082	82,012	96,745	129,829	150,584	1,320,492
2018	154,740	121,081	119,975	97,261	100,276	86,146	109,349	100,153	70,342	89,942	112,695	150,638	1,312,598
2019	147,714	98,552	116,377	90,039	91,727	81,739	100,157	94,674	87,612	98,618	112,609	146,320	1,266,137
2020	150,634	126,164	117,219	93,211	89,289	91,128	111,958	103,644	86,533	100,913	126,958	149,181	1,346,832
2021	151,923	132,351	117,698	95,324	88,510	89,335	114,977	114,763	58,293	98,449	123,064	145,645	1,330,331
2022	150,247	130,107	119,338	92,786	83,362	90,463	111,776	99,512	80,706	95,008	120,814	146,242	1,320,362
Before-Savings													
2023S	148,630	127,563	116,282	92,342	85,724	88,930	111,180	104,355	74,030	96,625	121,724	144,778	1,312,162
2024F	148,154	127,155	115,910	92,046	85,450	88,645	110,824	104,021	73,793	96,316	121,335	144,314	1,307,962
After-Savings													
2023S	148,150	127,096	115,852	91,964	85,397	88,640	110,904	104,066	73,703	96,247	121,295	144,311	1,307,625
2024F	147,193	126,221	115,051	91,290	84,797	88,068	110,274	103,444	73,140	95,560	120,475	143,379	1,298,891

2.4 COMMERCIAL (MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Historical Actuals													
2013	65,750	60,623	56,214	57,036	69,494	61,665	67,834	73,941	72,704	67,185	66,229	69,533	788,208
2014	80,354	73,607	69,309	70,566	73,342	72,255	76,262	75,406	66,710	60,531	66,112	81,292	865,746
2015	80,156	72,259	68,665	64,591	71,392	74,678	72,149	71,980	68,558	62,811	67,227	78,701	853,168
2016	81,888	75,253	71,663	71,537	69,950	67,264	75,224	78,198	68,802	70,075	79,061	92,524	901,438
2017	87,580	76,292	77,390	69,008	70,517	72,425	82,456	81,640	72,344	73,698	77,035	80,003	920,385
2018	85,824	76,573	78,401	70,827	73,372	72,287	81,199	81,422	70,961	73,116	75,837	82,157	921,978
2019	85,718	80,999	80,956	69,682	72,347	72,907	78,731	80,774	73,021	75,361	78,350	85,041	933,887
2020	87,508	79,773	76,660	64,284	65,222	67,351	78,479	81,698	74,157	76,661	80,042	85,339	917,174
2021	87,315	79,792	80,058	71,855	73,925	80,219	85,512	69,286	96,034	76,263	80,232	90,890	971,380
2022	93,663	80,863	81,664	72,557	71,986	71,849	84,690	88,145	74,835	75,357	80,089	93,445	969,143
Before-Savings													
2023S	91,951	82,346	81,646	71,485	72,319	75,155	85,172	81,902	83,920	78,188	82,324	92,357	978,766
2024F	93,611	83,835	83,122	72,779	73,628	76,515	86,710	83,382	85,437	79,602	83,812	94,025	996,458
After-Savings													
2023S	90,995	81,393	80,699	70,545	71,387	74,230	84,248	80,976	82,989	77,249	81,377	91,404	967,494
2024F	91,705	81,937	81,239	70,914	71,779	74,679	84,880	81,551	83,599	77,757	81,960	92,169	974,168

2.5 WHOLESALE (MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Historical Normalized Actuals													
2013	103,661	88,423	80,309	42,225	37,653	34,630	44,414	42,889	38,531	44,175	51,637	66,656	675,204
2014	64,115	50,647	51,900	41,917	35,985	34,959	43,081	42,482	38,972	41,116	53,678	68,270	567,123
2015	65,841	58,564	51,584	41,088	41,147	36,029	45,222	43,897	37,441	42,668	51,945	65,059	580,485
2016	64,687	55,006	49,218	43,812	36,262	35,106	48,506	43,480	37,096	43,408	59,685	58,167	574,434
2017	61,637	51,026	51,573	40,753	35,692	35,965	47,044	49,971	39,411	42,639	56,771	61,621	574,101
2018	65,721	51,837	50,293	43,769	41,467	33,766	45,024	47,275	36,478	47,576	54,103	67,407	584,715
2019	61,944	48,097	50,091	42,390	39,513	36,881	47,393	44,924	37,351	44,052	49,804	63,534	565,972
2020	64,233	56,219	48,768	39,333	33,066	35,088	44,642	44,913	39,548	45,075	55,660	62,943	569,488
2021	63,822	56,888	51,016	42,771	35,118	32,874	43,009	44,315	36,150	44,201	57,331	58,330	565,827
2022	64,786	56,887	52,353	41,723	35,185	36,472	44,017	44,848	38,048	41,846	54,139	65,162	575,466
Before-Savings													
2023S	67,256	57,713	51,399	42,651	38,415	37,652	45,051	46,169	40,005	46,783	57,049	64,421	594,563
2024F	67,539	57,947	51,611	42,840	38,640	37,900	45,329	46,428	40,224	47,006	57,281	64,693	597,438
After-Savings													
2023S	66,907	57,368	51,064	42,331	38,109	37,357	44,759	45,873	39,699	46,463	56,714	64,076	590,719
2024F	66,842	57,258	50,944	42,202	38,032	37,313	44,750	45,843	39,618	46,374	56,622	64,014	589,812

2.6 INDUSTRIAL (MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Historical Actuals													
2013	19,966	30,774	23,744	24,489	31,517	33,006	29,815	29,726	31,598	32,105	32,500	33,084	352,325
2014	35,943	32,746	26,411	34,532	30,112	32,770	29,719	22,362	30,032	38,104	35,138	33,043	380,912
2015	32,138	33,574	32,797	31,186	36,574	26,261	27,971	34,078	32,395	29,853	27,852	34,997	379,676
2016	32,901	29,835	33,180	28,953	27,588	31,785	31,632	32,805	30,120	33,350	28,559	32,687	373,396
2017	33,109	30,227	32,593	30,117	27,928	31,621	29,477	29,518	28,665	28,831	30,770	29,734	362,590
2018	30,089	33,113	31,062	30,455	32,718	39,030	38,264	35,307	33,245	30,034	33,591	35,836	402,744
2019	40,014	40,563	41,563	37,886	39,198	40,876	38,967	41,784	39,929	49,045	45,695	39,390	494,911
2020	41,115	37,485	36,324	30,596	32,632	32,899	39,933	39,350	35,590	36,265	39,250	39,794	441,233
2021	39,629	38,120	44,021	42,125	34,088	34,473	33,956	35,536	42,333	41,558	42,792	43,684	472,315
2022	46,629	42,908	45,937	46,285	47,294	50,460	43,070	43,215	46,443	44,094	50,708	51,418	558,461
Before-Savings													
2023S	47,521	43,708	46,835	47,439	48,308	51,817	43,854	44,015	47,362	44,605	51,508	52,182	569,155
2024F	48,181	44,325	47,433	48,156	48,954	52,472	44,495	44,665	48,074	45,222	52,168	52,806	576,954
After-Savings													
2023S	46,915	43,102	46,233	46,841	47,721	51,233	43,279	43,436	46,785	44,009	50,910	51,595	562,059
2024F	46,977	43,131	46,259	46,998	47,826	51,360	43,409	43,582	47,004	44,123	51,075	51,743	563,488

2.7 LIGHTING (MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Historical Actuals													
2013	1,532	863	1,003	1,112	1,186	1,101	1,151	1,069	1,135	1,132	1,080	1,114	13,479
2014	1,282	1,273	1,251	1,310	1,327	1,331	1,329	1,374	1,257	1,255	1,260	1,382	15,633
2015	1,319	1,339	1,261	1,321	1,372	1,382	1,299	1,347	1,248	1,349	1,295	1,359	15,891
2016	1,245	1,363	1,341	1,362	1,361	1,347	1,404	1,381	1,294	1,191	1,251	1,388	15,930
2017	1,394	1,233	1,390	1,286	1,339	1,301	1,383	1,382	1,289	1,335	1,270	1,330	15,932
2018	1,385	1,178	1,291	1,307	1,198	1,118	1,068	998	988	952	848	894	13,225
2019	907	808	873	943	965	937	917	949	955	947	909	928	11,039
2020	929	892	955	900	914	874	932	949	878	907	863	852	10,846
2021	838	774	836	795	858	787	802	805	770	851	776	791	9,682
2022	820	724	772	760	790	729	784	762	767	800	766	788	9,262
Before-Savings													
2023S	804	743	797	763	796	743	783	782	751	796	748	756	9,262
2024F	804	743	797	763	796	743	783	782	751	796	748	756	9,262
After-Savings													
2023S	796	735	789	756	790	737	776	775	744	788	740	748	9,173
2024F	787	727	781	749	783	730	770	769	737	781	732	739	9,084

2.8 IRRIGATION (MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Historical Actuals													
2013	1,557	1,228	759	880	2,480	3,974	4,986	6,729	7,519	4,955	2,970	1,666	39,704
2014	633	549	932	2,227	4,512	7,013	8,146	6,822	4,501	2,578	1,267	847	40,025
2015	790	680	1,089	2,698	5,718	7,925	8,506	7,700	5,192	3,074	1,768	863	46,003
2016	822	834	1,341	3,172	4,888	5,748	7,561	7,778	4,724	2,694	1,739	765	42,065
2017	780	670	772	1,096	3,035	6,160	9,587	9,343	5,898	3,231	719	649	41,939
2018	700	662	761	1,419	4,521	6,271	8,461	8,024	4,348	2,465	681	666	38,979
2019	663	630	650	1,694	5,103	6,429	6,958	7,254	3,381	1,741	835	640	35,978
2020	708	660	662	1,987	3,535	3,752	7,936	8,743	5,588	2,317	709	662	37,260
2021	674	606	641	2,272	5,957	7,621	10,099	7,568	4,242	2,508	701	751	43,640
2022	760	655	718	1,400	3,452	4,028	7,631	8,660	5,441	3,049	965	804	37,563
Before-Savings													
2023S	699	628	660	1,848	4,227	5,029	8,381	8,154	4,987	2,571	776	724	38,684
2024F	699	628	660	1,848	4,227	5,029	8,381	8,154	4,987	2,571	776	724	38,684
After-Savings													
2023S	698	627	659	1,846	4,222	5,018	8,364	8,134	4,970	2,561	771	722	38,592
2024F	698	626	657	1,844	4,217	5,007	8,346	8,113	4,954	2,552	767	720	38,500

2.9 SYSTEM PEAK (MW)

System Peak (MW)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Winter	Summer
Historical Normalized Actuals														
2013	720	631	549	493	515	442	600	565	523	502	598	698	698	600
2014	651	580	562	469	403	482	620	605	412	467	572	645	693	620
2015	693	679	568	488	501	523	611	587	437	514	669	631	685	611
2016	685	683	569	540	490	582	587	593	443	480	613	724	755	593
2017	755	673	595	510	597	505	600	605	561	515	594	648	714	605
2018	714	648	583	516	602	533	630	631	429	459	609	659	682	631
2019	678	682	651	514	568	502	626	639	538	562	622	701	732	639
2020	732	680	609	500	482	515	666	665	551	549	631	667	731	666
2021	711	731	555	495	488	653	597	635	486	509	628	675	685	653
2022	685	676	572	490	432	615	681	689	629	480	673	734	734	689
Before-Savings														
2023S	723	701	615	519	494	607	682	676	527	537	655	742	788	700
2024F	728	705	619	522	497	611	687	681	531	541	660	747	793	705
After-Savings														
2023S	719	696	611	515	490	603	678	672	523	533	651	738	783	696
2024F	720	696	611	514	490	603	679	673	523	533	652	739	785	697

Note: The peaks shown in the table above are seasonal peaks. The seasonal winter peak is based on November and December of the current year and January and February of the following year. The seasonal summer peak is based on June, July and August of the current year and includes the June 2021 Heat Dome.

3. CUSTOMER FORECAST

3.1 CUSTOMERS

Customer Count	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023S	2024F
Residential	111,862	113,431	114,166	115,772	117,748	120,291	122,465	124,966	126,678	129,131	131,323	133,291
Commercial	13,662	14,363	14,976	15,073	15,398	15,678	15,956	16,165	16,594	16,773	16,930	17,290
Wholesale	6	6	6	6	6	6	6	6	6	6	6	6
Industrial	47	49	50	50	50	52	51	43	42	42	42	42
Lighting	1,644	1,620	1,590	1,559	1,511	1,482	1,467	1,443	1,407	1,380	1,357	1,330
Irrigation	1,097	1,103	1,095	1,090	1,080	1,078	1,082	1,091	1,103	1,103	1,103	1,103
Total Direct	128,318	130,572	131,883	133,550	135,793	138,587	141,027	143,714	145,830	148,435	150,761	153,063

3.2 CUSTOMER ADDITIONS

Customer Additions	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023S	2024F
Residential	(433)	1,569	735	1,606	1,976	2,543	2,174	2,501	1,712	2,453	2,192	1,969
Commercial	489	701	613	97	325	280	278	209	429	179	157	360
Wholesale	(1)	-	-	-	-	-	-	-	-	-	-	-
Industrial	(4)	2	1	-	-	2	(1)	(8)	(1)	-	-	-
Lighting	(95)	(24)	(30)	(31)	(48)	(29)	(15)	(24)	(36)	(27)	(23)	(26)
Irrigation	6	6	(8)	(5)	(10)	(2)	4	9	12	-	-	-
Total Direct	(38)	2,254	1,311	1,667	2,243	2,794	2,440	2,687	2,116	2,605	2,326	2,302

4. NORMALIZED AFTER-SAVINGS USE PER CUSTOMER (UPC)

MWh/Customer	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023S	2024F
Residential	12.48	11.51	11.41	11.27	11.31	11.03	10.43	10.89	10.57	10.32	10.04	9.82

5. LOAD

5.1 AFTER-SAVINGS LOAD

Energy (GWh)	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023S	2024F
Residential	1,352.9	1,296.5	1,298.1	1,295.6	1,320.5	1,312.6	1,266.1	1,346.8	1,330.3	1,320.4	1,307.6	1,298.9
Commercial	788.2	865.7	853.2	901.4	920.4	922.0	933.9	917.2	971.4	969.1	967.5	974.2
Wholesale	675.2	567.1	580.5	574.4	574.1	584.7	566.0	569.5	565.8	575.5	590.7	589.8
Industrial	352.3	380.9	379.7	373.4	362.6	402.7	494.9	441.2	472.3	558.5	562.1	563.5
Lighting	13.5	15.6	15.9	15.9	15.9	13.2	11.0	10.8	9.7	9.3	9.2	9.1
Irrigation	39.7	40.0	46.0	42.1	41.9	39.0	36.0	37.3	43.6	37.6	38.6	38.5
Net	3,221.9	3,165.9	3,173.4	3,202.8	3,235.4	3,274.2	3,307.9	3,322.8	3,393.2	3,470.3	3,475.7	3,473.9
Losses & Company Use	278.1	270.1	272.4	273.8	282.3	285.1	286.9	287.9	299.7	314.6	298.9	298.7
Gross	3,500.0	3,436.0	3,445.8	3,476.6	3,517.7	3,559.4	3,594.8	3,610.8	3,692.8	3,784.8	3,774.5	3,772.7
System Peak (MW)												
Winter Peak	698.1	692.6	685.0	754.7	713.6	682.2	732.4	730.8	684.8	734.3	783.4	785.0
Summer Peak	600.4	619.5	611.0	593.0	604.8	630.9	639.4	666.2	652.9	689.1	696.2	697.3

5.2 NORMALIZED AFTER-SAVINGS WHOLESALE LOAD

Wholesale (GWh)	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023S	2024F
BCH Lardeau	6.3	6.3	6.5	5.9	8.4	7.8	7.1	6.1	5.9	5.0	6.6	6.5
BCH Kingsgate	4.9	4.6	4.8	4.9	4.6	4.7	4.6	5.0	4.1	4.0	4.6	4.6
City of Grand Forks	41.1	39.5	40.7	40.5	38.7	45.8	36.9	37.5	36.3	37.0	37.5	37.5
City of Nelson	82.7	80.9	83.0	79.6	86.1	88.0	83.8	82.0	85.6	86.0	84.5	83.2
City of Penticton	348.4	341.9	348.4	345.2	338.0	340.0	338.4	340.3	337.0	347.0	357.9	357.9
District of Summerland	97.9	94.0	97.1	98.2	98.2	98.5	95.1	98.5	96.9	96.0	99.7	100.1
City of Kelowna	93.9	-	-	-	-	-	-	-	-	-	-	-
Total	675.2	567.1	580.5	574.4	574.1	584.7	566.0	569.5	565.8	575.0	590.7	589.8

5.3 DSM (GWH) WITHOUT LOSSES

Energy (GWh)	2018	2019	2020	2021	2022	2023S	2024F
Demand Side Management	(31.4)	(25.8)	(26.3)	(30.0)	(35.9)	(26.9)	(52.8)

6. VARIANCES TO FORECAST

6.1 CUSTOMER COUNT VARIANCE

Customer Count	2017	2018	2019	2020	2021	2022
Actual						
Residential	117,748	120,291	122,465	124,966	126,678	129,131
Commercial	15,398	15,678	15,956	16,165	16,594	16,773
Wholesale	6	6	6	6	6	6
Industrial	50	52	51	43	42	42
Lighting	1,511	1,482	1,467	1,443	1,407	1,380
Irrigation	1,080	1,078	1,082	1,091	1,103	1,103
Total	135,793	138,587	141,027	143,714	145,830	148,435
Forecast						
Residential	116,031	117,774	120,405	124,076	124,603	128,941
Commercial	15,813	16,122	16,405	16,220	16,579	16,975
Wholesale	6	6	6	6	6	6
Industrial	50	50	51	57	59	43
Lighting	1,590	1,559	1,511	1,425	1,393	1,406
Irrigation	1,095	1,090	1,080	1,082	1,082	1,091
Total	134,585	136,602	139,459	142,865	143,721	148,462
Variance (customers)						
Residential	1,717	2,517	2,060	890	2,075	190
Commercial	(415)	(444)	(449)	(55)	15	(202)
Wholesale	0	0	0	0	0	0
Industrial	0	2	0	(14)	(17)	(1)
Lighting	(79)	(77)	(44)	18	14	(26)
Irrigation	(15)	(12)	2	9	21	12
Total	1,208	1,986	1,569	849	2,109	(27)
Variance (%)						
Residential	1.5%	2.1%	1.7%	0.7%	1.6%	0.1%
Commercial	-2.7%	-2.8%	-2.8%	-0.3%	0.1%	-1.2%
Wholesale	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Industrial	0.0%	3.8%	0.0%	-32.6%	-40.5%	-2.4%
Lighting	-5.2%	-5.2%	-3.0%	1.3%	1.0%	-1.9%
Irrigation	-1.4%	-1.1%	0.2%	0.8%	1.9%	1.1%
Total	0.9%	1.4%	1.1%	0.6%	1.4%	0.0%

6.2 LOAD VARIANCE, NORMALIZED/HISTORIC ACTUAL TO FORECAST[1]

Energy (GWh)	2017	2018	2019	2020	2021	2022
Historic						
Residential	1,320.5	1,312.6	1,266.1	1,346.8	1,330.3	1,320.4
Commercial	920.4	922.0	933.9	917.2	971.4	969.1
Wholesale	574.1	584.7	566.0	569.5	565.8	575.5
Industrial	362.6	402.7	494.9	441.2	472.3	558.5
Lighting	15.9	13.2	11.0	10.8	9.7	9.3
Irrigation	41.9	39.0	36.0	37.3	43.6	37.6
Net	3,235.4	3,274.2	3,307.9	3,322.8	3,393.2	3,470.3
Gross	3,517.7	3,559.4	3,594.8	3,610.8	3,692.8	3,784.8
Forecast						
Residential	1,353.0	1,280.0	1,349.3	1,325.6	1,255.4	1,283.2
Commercial	879.4	912.0	935.2	901.7	952.3	945.5
Wholesale	587.3	586.0	594.0	567.5	583.5	559.5
Industrial	407.0	379.0	385.0	453.0	536.7	470.4
Lighting	14.4	15.0	13.0	10.6	9.9	10.3
Irrigation	40.3	41.0	42.0	35.3	35.8	37.1
Net	3,282.2	3,213.0	3,318.5	3,293.7	3,373.7	3,306.0
Gross	3,559.0	3,485.0	3,602.0	3,602.0	3,664.0	3,591.0
Variance (GWh)						
Residential	(32.5)	32.6	(83.2)	21.3	74.9	37.1
Commercial	41.0	10.0	(1.3)	15.5	19.1	23.6
Wholesale	(13.2)	(1.3)	(28.0)	2.0	(17.7)	16.0
Industrial	(44.4)	23.7	109.9	(11.8)	(64.3)	88.1
Lighting	1.5	(1.8)	(2.0)	0.2	(0.3)	(1.0)
Irrigation	1.7	(2.0)	(6.0)	2.0	7.8	0.5
Net	(46.8)	61.2	(10.6)	29.2	19.5	164.3
Gross	(41.3)	74.4	(7.2)	8.8	28.9	193.9
Variance (%)						
Residential	-2.5%	2.5%	-6.6%	1.6%	5.6%	2.8%
Commercial	4.4%	1.1%	-0.1%	1.7%	2.0%	2.4%
Wholesale	-2.3%	-0.2%	-5.0%	0.4%	-3.1%	2.8%
Industrial	-12.3%	5.9%	22.2%	-2.7%	-13.6%	15.8%
Lighting	9.4%	-13.4%	-17.8%	2.1%	-2.8%	-10.7%
Irrigation	3.9%	-5.2%	-16.7%	5.3%	17.9%	1.3%
Net	-1.4%	1.9%	-0.3%	0.9%	0.6%	4.7%
Gross	-1.2%	2.1%	-0.2%	0.2%	0.8%	5.1%

[1] Residential and Wholesale historic loads shown are normalized loads. All other rate classes show historic actual loads.

6.3 NORMALIZED AFTER-SAVINGS ANNUAL PERCENT GROWTH

Energy (GWh)	2017	2018	2019	2020	2021	2022	2023S	2024F
Residential	1,320.5	1,312.6	1,266.1	1,346.8	1,330.3	1,320.4	1,307.6	1,298.9
Commercial	920.4	922.0	933.9	917.2	971.4	969.1	967.5	974.2
Wholesale	574.1	584.7	566.0	569.5	565.8	575.5	590.7	589.8
Industrial	362.6	402.7	494.9	441.2	472.3	558.5	562.1	563.5
Lighting	15.9	13.2	11.0	10.8	9.7	9.3	9.2	9.1
Irrigation	41.9	39.0	36.0	37.3	43.6	37.6	38.6	38.5
Net	3,235.4	3,274.2	3,307.9	3,322.8	3,393.2	3,470.3	3,475.7	3,473.9
Losses & Company Use	282.3	285.1	286.9	287.9	299.7	314.6	298.9	298.7
Gross	3,517.7	3,559.4	3,594.8	3,610.8	3,692.8	3,784.8	3,774.5	3,772.7
System Peak								
Winter Peak (MW)	713.6	682.2	732.4	730.8	684.8	734.3	783.4	785.0
Summer Peak (MW)	604.8	630.9	639.4	666.2	652.9	689.1	696.2	697.3

Growth Year over Year	2017	2018	2019	2020	2021	2022	2023S	2024F
Residential	1.9%	-0.6%	-3.5%	6.4%	-1.2%	-0.7%	-1.0%	-0.7%
Commercial	2.1%	0.2%	1.3%	-1.8%	5.9%	-0.2%	-0.2%	0.7%
Wholesale	-0.1%	1.8%	-3.2%	0.6%	-0.6%	1.7%	2.7%	-0.2%
Industrial	-2.9%	11.1%	22.9%	-10.8%	7.0%	18.2%	0.6%	0.3%
Lighting	0.0%	-17.0%	-16.5%	-1.7%	-10.7%	-4.3%	-1.0%	-1.0%
Irrigation	-0.3%	-7.1%	-7.7%	3.6%	17.1%	-13.9%	2.7%	-0.2%
Net	1.0%	1.2%	1.0%	0.5%	2.1%	2.3%	0.2%	0.0%
Losses & Company Use	3.1%	1.0%	0.6%	0.4%	4.1%	5.0%	-5.0%	0.0%
Gross	1.2%	1.2%	1.0%	0.4%	2.3%	2.5%	-0.3%	0.0%
System Peak								
Winter Peak (MW)	-5.4%	-4.4%	7.4%	-0.2%	-6.3%	7.2%	6.7%	0.2%
Summer Peak (MW)	2.0%	4.3%	1.4%	4.2%	-2.0%	5.5%	1.0%	0.1%

Customer Count	2017	2018	2019	2020	2021	2022	2023S	2024F
Residential	117,748	120,291	122,465	124,966	126,678	129,131	131,323	133,291
Commercial	15,398	15,678	15,956	16,165	16,594	16,773	16,930	17,290
Wholesale	6	6	6	6	6	6	6	6
Industrial	50	52	51	43	42	42	42	42
Lighting	1,511	1,482	1,467	1,443	1,407	1,380	1,103	1,103
Irrigation	1,080	1,078	1,082	1,091	1,103	1,103	1,357	1,330
Total Direct	135,793	138,587	141,027	143,714	145,830	148,435	150,761	153,063

Growth Year over Year	2017	2018	2019	2020	2021	2022	2023S	2024F
Residential	1.7%	2.2%	1.8%	2.0%	1.4%	1.9%	1.7%	1.5%
Commercial	2.2%	1.8%	1.8%	1.3%	2.7%	1.1%	0.9%	2.1%
Wholesale	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Industrial	0.0%	4.0%	-1.9%	-15.7%	-2.3%	0.0%	0.0%	0.0%
Lighting	-3.1%	-1.9%	-1.0%	-1.6%	-2.5%	-1.9%	-20.1%	0.0%
Irrigation	-0.9%	-0.2%	0.4%	0.8%	1.1%	0.0%	23.0%	-1.9%
Total Direct	1.7%	2.1%	1.8%	1.9%	1.5%	1.8%	1.6%	1.5%

6.4 RESIDENTIAL UPC, NORMALIZED ACTUAL TO FORECAST

Residential UPC (MWh)	2020	2021	2022
After- Savings Normalized Actual UPC	10.89	10.57	10.32
Forecast	10.75	10.10	10.04
Variance	0.13	0.48	0.29
Variance (%)	1.2%	4.5%	2.8%

6.5 WINTER PEAK, ACTUAL TO FORECAST

Winter Peak (MW)	2020	2021	2022
Actual Peak	725.0	777.0	835.0
Forecast	737.0	748.0	716.5
Variance	(12.0)	29.0	118.5
Variance (%)	-2%	4%	17%

Note: The peaks reflected in this table are the actual seasonal peaks are not normalized.

6.6 SYSTEM LOAD FACTOR

The following table shows annual after-savings gross load, peak load and load factor. The annual load factor is calculated as annual load ÷ peak hourly load x number of hours in a year (8,760).

Year	Energy (MWh)	Peak (MW)	Load Factor
2017	3,517,718	714	0.56
2018	3,559,367	682	0.60
2019	3,594,813	732	0.56
2020	3,610,765	731	0.56
2021	3,692,835	684	0.62
2022	3,784,830	733	0.59
2023S	3,774,539	783	0.55
2024F	3,772,679	785	0.55

Note: The peaks in this table represent annual peaks meaning they happened in the calendar year and are not the seasonal peaks.

Appendix A3

Load Forecast Methods

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1. LOAD FORECAST METHODS

This appendix describes FBC's load forecast methods on which the forecast in Section 3 of the Application is based.

In the figures provided in this appendix, the following three time frames are shown:

- Actual Years: Actual years are those for which actual data exists for the full calendar year[1]. For the 2024 Annual Review the latest calendar year for which full actual data exists is the 2022 calendar year.
- Seed Year: The Seed Year is the year prior to the first forecast year. The Seed Year is forecast based on the latest years of actual data available, and will be different than the original forecast for that year in the previous filing. For example, for this Application the Seed Year is 2023 (2023S) and the Seed Year forecast is based on the latest actual years, including 2022. As such, the 2023 Seed Year forecast in this Application will differ from the 2023 Forecast presented in the Annual Review for 2023 Rates, for which 2022 actual data was not available.
- Forecast Year(s): This is the year or years for which the forecast is being developed. This can be one year (in the case of the Annual Review) or a range of two or more years depending on the filing. In this Application, 2024 is the Forecast Year (2024F).

1.1 *WEATHER NORMALIZATION*

Electricity consumption is impacted by weather, particularly by temperature. For example, load requirements in an extremely cold winter month can be significantly higher than requirements in normal weather conditions in the same month, due to additional heating loads. As the load forecast is made under an assumption of normal weather, it is necessary to remove those extreme weather effects from the historical data. This is the first step in forecasting.

Statistical tests were made to check whether the residential, wholesale, commercial and irrigation loads were sensitive to temperature due to heating and cooling demands and whether the irrigation load was sensitive to the amount of precipitation[2]. The results from the regression for these four rate classes are shown below. The regressions result in high R^2 values for all seasons for the residential and wholesale load classes; therefore these classes are normalized. The commercial class shows a low R^2 value for all seasons and the irrigation class for the winter, summer and fall seasons; therefore, these classes were not normalized.

[1] FBC's load forecast is developed using only full years of historical data. FBC requires the full year of load data in order to validate it, including the review of and potential adjustments to unbilled energy. For this reason partial year data is not used in forecasting.
[2] Industrial and lighting loads are typically insensitive to the weather.

Table A3-1: Residential Regression Table

Residential	Winter	Spring	Summer	Fall
Intercept	35,802	71,302	76,725	70,811
Slope HDD	180	108	-	93
Slope CDD	-	-	250	-
Adjusted R^2	0.77	0.75	0.83	0.78

Table A3-2: Wholesale Regression Table

Wholesale	Winter	Spring	Summer	Fall
Intercept	63,808	60,024	33,068	34,997
Slope HDD	60	49	-	32
Slope CDD	-	-	103	-
Adjusted R^2	0.91	0.95	0.85	0.79

Table A3-3: Commercial Regression Table

Commercial	Winter	Spring	Summer	Fall
Intercept	50,957	49,648	69,253	71,660
Slope HDD	25	18	-	(2)
Slope CDD	-	-	78	-
Adjusted R^2	0.31	0.28	0.36	(0.05)

Table A3-4: Irrigation Regression Table

Irrigation	Winter	Spring	Summer	Fall
Intercept	1,382	5,363	5,017	5,846
Slope HDD	(1)	(12)	-	(11)
Slope CDD	-	-	24	-
Adjusted R^2	0.01	0.78	0.53	0.52

Steps for weather (temperature) normalization are as follows:

1. Calculate monthly Heating Degree Days (HDD)[3] and Cooling Degree Days (CDD)[4] for the Penticton weather station.
2. Calculate 10-year HDD and CDD averages for each month of the year. These are used as the parameters of normal weather.
3. For each of the residential and wholesale classes, regress load on HDD or CDD on a seasonal basis. Four seasons were defined: winter (November to February), spring

[3] Heating degree-days for a given day are the number of Celsius degrees that the mean temperature is below 18 Celsius degrees.
[4] Cooling degree-days for a given day are the number of Celsius degrees that the mean temperature is above 18 Celsius degrees.

(March to May), summer (June to August) and fall (September to October). Thus all monthly load and degree day data for each season is used and four separate regressions are calculated for each class. The City of Kelowna (CoK) Event variables were included in the regressions to recognize the integration of the CoK in 2013 into the FBC direct customer base.

4. To normalize a month, e.g. February 2022:

   (a) obtain the month's HDD (or CDD) information from Environment Canada;

   (b) calculate the deviation from the 10-year average (2013-2022) HDD (CDD) as found in Step 2;

   (c) apply the regression slope obtained in Step 3 to this deviation to come up with a normalization adder; and

   (d) add the normalization adder to the month's load (residential or wholesale).

The general equation to normalize load requirements in month t is shown below.

$$Normalized\ Load_t = Load_t - HDD\ Slope_t \times (HDD_t - Normal\ HDD_t)$$

$$where\ HDD\ is\ Heating\ Degree\ Days\ and\ t = Spring, Fall\ and\ Winter$$

And

$$Normalized\ Load_t = Load_t - CDD\ Slope_t \times (CDD_t - Normal\ CDD_t)$$

$$where\ CDD\ is\ Cooling\ Degree\ Days\ and\ t = Summer$$

1.2 *LOAD FORECAST*

FBC forecasts energy requirements by customer class based on weather normalized historical loads. These are referred to as the "before-savings[5]" loads. DSM savings that are incremental to those embedded in historical loads (up to and including 2022) are also forecast for each customer class and subtracted from the before-savings loads to arrive at the "after-savings" loads. This section discusses the before-savings forecast load requirements for each of FBC's load classes.

1.2.1 Residential

The formula to forecast the expected before-savings residential load in year *t* is:

$$Before\ Savings\ Load_t = UPC_t \times Average\ Customer\ Count_t$$

where UPC (use per customer in MWh per customer per year) is before-savings.

[5] The term "before-savings" is used in the remainder of this section and refers to "before incremental savings after 2022".

The before-savings UPC was based on a 10-year historic trend of annual UPC values from 2013 to 2022.

Table A3-5: Results of UPC Trend Analysis

Regression	UPC
Start Year	2013
End Year	2022
R^2	0.825
Adjusted R^2	0.803
df	9
Intercept	395
Slope UPC	-0.19

Next, average customer count in year *t* is calculated as:

$$Average\ Customer\ Count_t = \frac{(Year\ End\ Count_t + Year\ End\ Count_{t-1})}{2}$$

The year-end customer count was based on the least squares regression model below.

$$Year\ End\ Customer\ Count_t = b_0 + b_1 \times Population_t$$

$Population_t$ is the population data supplied by BC Stats for the Company's direct service area.

Table A3-6: Results of Residential Customer Count Regression

Regression	Residential
Start Year	2017
End Year	2022
R^2	0.996
Adjusted R^2	0.995
df	5
Intercept	(3,342)
Slope Population	0.46

The residential class represented 38.0 percent of the net load in 2022.

1.2.2 Commercial

The expected before-savings commercial load in year *t* is forecast based on the provincial GDP supplied by the CBOC. The relationship was estimated from the following equation.

$$Before\ Savings\ Load_t = (b_0 + b_1 \times GDP_t + b_2 \times CoK\ Event_t) + FBC\ EV\ DC\ Fast\ Chargers$$

The CoK_t is a binary variable for the City of Kelowna integration event in 2013. Coefficients b0, b1 and b2 are obtained from an ordinary least squares (OLS) regression analysis on the 2008 to 2022 data. The FBC EV DCFCs are Electric Vehicle Direct Current Fast Chargers serviced by FBC which are added to the forecast. The commercial class represented 27.9 percent of the net load in 2022.

Table A3-7: Results of Commercial Regression

Regression	Commercial
Start Year	2008
End Year	2022
R^2	0.987
Adjusted R^2	0.985
df	14
Intercept	186,072
Slope GDP	2
Slope CoK Event	136,787

1.2.3 Wholesale

The Company forecasts the wholesale load based on load surveys from the wholesale customers. For this forecast, FBC received surveys from all the wholesale customers. FBC then summed the wholesale customers' forecasts to calculate the before-savings wholesale load forecast. This approach recognizes that in the near to medium term, the wholesale customers themselves are best able to forecast their load growth based on their knowledge of their customer mix, load behaviors, development projects with associated load requirements, etc. The wholesale class represented 16.6 percent of the net load in 2022.

1.2.4 Industrial

The before-savings industrial load is the sum of forecasts supplied by those individual customers who responded to the load survey and, for customers who did not respond, escalation of the customer's load in the preceding year by the CBOC forecast GDP growth rates for the industrial sector the customer is in. 76 percent of FBC's industrial customers responded to the surveys, accounting for 91 percent of 2022 load.

FBC assumes no new industrial customers in the current forecast unless there is a confirmed commitment from an industrial customer. FBC works with key account managers to identify new customers and existing customers with expansion plans that have commited contracts that are being added to the system. The key account managers work with the new customers directly and relay the load requirements to the forecasting group. The industrial class represented 16.1 percent of the net load in 2022.

1.2.5 Irrigation

The before-savings irrigation load forecast uses a five-year average so that the extreme weather events such as those that occurred in 2022 are included in the forecast but do not overly influence it. The irrigation class represented 1.1 percent of the net load in 2022.

1.2.6 Lighting

The before-savings lighting load uses the 2022 actuals due to the variability in the load primarily due to streetlight LED replacement programs which reduced the loads from 2018 to 2022. The lighting class represented 0.3 percent of the net load in 2022.

1.2.7 Demand Side Mangment (DSM) Savings

FBC forecasts load reductions resulting from its DSM programs.

The forecast of DSM savings is consistent with the Company's approved 2019-2022 DSM Plan. DSM measures are grouped into applicable programs that are then added to produce the three primary sector (residential, commercial & industrial) annual plan savings targets. Finally, the annual sector targets beginning with the Seed Year are converted into a cumulative time series, and disaggregated into the customer rate classes and commensurate system loss reductions.

1.3 *PEAK DEMAND FORECAST*

The peak demand forecast is produced by taking the 10-year average (2013-2022) of historical peak data. The historical peak data is escalated by the gross load growth rate before it is averaged to account for the growth of demand on the FBC system. Self-generating customers are removed from the historical load data since the underlying trends that impact other loads do not apply. Seasonal peaks were used for both the winter and the summer. The 12 monthly peaks, as well as the seasonal peaks, were then escalated by the annual load growth rates in the forecast period to produce forecast monthly peaks. The winter peak and the summer peak are assumed to replace monthly peaks in December and July, respectively.

The after DSM peak forecast was calculated by subtracting DSM capacity savings forecast from the before DSM peak forecast for each month in each year.

Appendix B
PRIOR YEAR DIRECTIVES

No.	Decision Page No.	Directive No.	Reference	Description / Details	Status	Section in this Application
G-166-20 – FBC MULTI-YEAR RATE PLAN FOR 2020 THROUGH 2024						
1.	75	24	General Flow-through Deferral Account	The Panel directs [FBC] to provide a detailed analysis of the individual forecast variances recorded in the Flow-through deferral account in each Annual Review.	Ongoing during the MRP term	Section 12.4.2.1
2.	87	32	Efficiency Carry-Over Mechanism	Therefore, the Panel determines the following process for the handling of an ECM application: 1. An ECM can be applied for at any time in the last three years of the MRPs, either in advance or following the action or initiative being undertaken. 2. For proposed activities where identifiable savings are expected to extend beyond the term of the MRP, FortisBC is to file an ECM proposal describing the initiative, its timing, costs and benefits and savings. 3. Parties will have the opportunity to review and comment on the proposal and the BCUC will determine whether to approve the ECM proposal (an Approved ECM Initiative). 4. FortisBC must submit details of continued savings annually under an Approved ECM Initiative as part of the Annual Review process. The net savings will be shared equally between ratepayers and the Utilities will carry forward past the end of the MRP for a maximum period of three years.	No approved ECM initiatives to report on	n/a
3.	99	35	SAIDI and SAIFI major events	The Panel also directs FBC to include a discussion of major events relevant to the SAIDI and SAIFI results in future Annual Review materials.	Ongoing during the MRP term	Section 13
4.	99-100		SQI Informational Indicators	In addition to the SQIs, the Panel approves the following informational indicators for the Utilities: • Customer Satisfaction Index (measures overall customer satisfaction) – FEI and FBC. • Average Speed of Answer (average number of seconds to answer emergency and non-emergency calls) – FEI and FBC. • Generator Forced Outage Rate (percent of time a generating unit is removed from service due to component failure or other events) – FBC only. • Interconnection Utilization (percent of time that an interconnection point was available and providing electrical service to wholesale customers) – FBC only. The Utilities are directed to report on these informational indicators along with the SQIs as part of the Annual Review process.	Ongoing during the MRP term	Section 13

No.	Decision Page No.	Directive No.	Reference	Description / Details	Status	Section in this Application
5.	118	42	System Operations, Integrity and Security Expenditures	The Panel directs FBC to provide the following information related to System Operations, Integrity and Security expenditures in its future revenue requirements applications over the term of the Proposed MRPs: 1. A breakdown and explanation of both annual and cumulative variances between forecast/actual and formula O&M related to System Operations, Integrity and Security expenditures, which quantify the variances attributable to the following areas: • Tree management; • Generation dam safety; • Network operations apprentice program; • Cyber security; • Data analytics; and • Any other significant factors or miscellaneous items. 2. A description of how FBC is prioritizing its System Operations, Integrity and Security expenditures.	Ongoing during the MRP term	Section 6.2.1
G-374-21 – FBC ANNUAL REVIEW FOR 2022 RATES						
6.	32	8	EV Charging Updates	The Panel directs FBC to include in future Annual Review filings an update on its EV DCFC charging stations' costs and revenues for the previous fiscal year along with a forecast of costs and revenues for the test period.	Ongoing	Sections 3.6, 5.8, 6.3.4 and 7.2.2.1
G-14-23 – FBC PRINCETON BRIDGE STREET PROPERTIES DISPOSITION						
7.	n/a	4	Princeton Office Disposition Deferral Account	FBC is directed to provide details of the final balance in the Princeton Office Disposition deferral account in the FBC Annual Review for 2024 Rates.	Complete	Section 7.6.2.1

Appendix C
DRAFT ORDER

bcuc
British Columbia
Utilities Commission

Suite 410, 900 Howe Street
Vancouver, BC Canada V6Z 2N3
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ORDER NUMBER
G-xx-xx

IN THE MATTER OF
the *Utilities Commission Act*, RSBC 1996, Chapter 473

and

FortisBC Inc.
Annual Review for 2024 Rates

BEFORE:
[Panel Chair]
Commissioner
Commissioner

on Date

ORDER

WHEREAS:

A. On June 22, 2020, the British Columbia Utilities Commission (BCUC) issued its Decision and Order G-165-20 for FortisBC Energy Inc. and Order G-166-20 for FortisBC Inc. (FBC) approving a Multi-Year Rate Plan for 2020 through 2024 (MRP Decision). In accordance with the MRP Decision, FBC is to conduct an annual review (Annual Review) process to set rates for each year;

B. By letter dated June 28, 2023, FBC proposed a regulatory timetable for the Annual Review of its 2024 rates;

C. By Order G-191-23, the BCUC established a regulatory timetable for the Annual Review for FBC's 2024 rates, which included FBC filing its Annual Review materials, the deadline for intervener registration, one round of information requests, a workshop, FBC's response to undertakings at the workshop, and written final and reply arguments;

D. On August 4, 2023, FBC submitted its materials for the Annual Review for 2024 Rates Application (Application). In the Application, FBC requests a 4.83 percent rate increase over the 2023 rates, effective January 1, 2024, among other things; and

E. The BCUC has reviewed the Application, evidence and arguments filed in the proceeding and makes the following determinations.

NOW THEREFORE pursuant to sections 59 to 61 of the *Utilities Commission Act*, for the reasons stated in the decision issued concurrently with this order, the BCUC orders as follows:

1. FBC is approved to recover the 2024 revenue requirement and resultant rate change on a permanent basis, effective January 1, 2024, as filed in the Application and subject to any adjustments identified by FBC during

the regulatory process and from any directives or determinations made by the BCUC in its decision on the Application.

2. FBC is approved to establish the following rate base deferral accounts:

    a. 2025 Multi-year Rate Plan (MRP) Application deferral account, with the amortization period to be determined in a future proceeding;

    b. 2024 Mandatory Reliability Standards (MRS) Audit deferral account, with an amortization period of three years, commencing January 1, 2024;

    c. PST Rebate on Select Machinery and Equipment deferral account, with an amortization period of one year, commencing January 1, 2024;

    d. BC Cost of Living Credit deferral account, with an amortization period of one year, commencing January 1, 2024; and

    e. Climate Change Operational Adaptation (CCOA) Plan deferral account, with an amortization period of four years, commencing January 1, 2024.

3. FBC is directed to file as a compliance filing, the finalized financial schedules and updated tariff pages within 10 days from the date of the issuance of this order.

DATED at the City of Vancouver, in the Province of British Columbia, this (XX) day of (Month Year).

BY ORDER

(X. X. last name)
Commissioner

Consumer Price Index, monthly, not seasonally adjusted 1 2 3
Frequency: Monthly
Table: 18-10-0004-01 (formerly CANSIM 326-0020)
Release date: 2023-10-17
Geography: Canada, Province or territory, Census subdivision, Census metropolitan area, Census metropolitan area part

Geography	Whitehorse, Yukon 4					
Products and product groups 3 5	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16
	2002=100					
All-items	124.1	123.7	124.2	124.4	125.2	126.6
Food 6	135.6	135.3	133.8	133.2	133.4	133.4
Shelter 7	143.3	141.3	141.5	142.4	142.6	144.5
Household operations, furnishings and equipment	107.1	107.8	109.6	108.8	108.7	109.9
Clothing and footwear	101.1	100.7	101	101.6	100.8	99.8
Transportation	123.2	121.2	122.7	123.9	126.6	131.5
Gasoline	121.3	112.5	117.1	123.2	132.6	150.8
Health and personal care	121.7	123.2	121.9	123.2	124.7	123.7
Recreation, education and reading	94	95.5	97	96.2	97.4	98
Alcoholic beverages, tobacco products and recreational cannabis	154.4	155.1	155.3	155.3	155.5	155.7
All-items excluding food and energy 8	120.4	121	121.7	121.5	121.9	123
All-items excluding energy 8	123.3	123.7	124.1	123.8	124.2	125.1
Energy 8	131.5	122.3	125	129.6	134.5	142.1
Goods 9	114.5	113.2	113.9	114.4	115.3	116.8
Services 10	135.1	135.7	136	135.8	136.5	138

Consumer Price Index, monthly, not seasonally adjusted 1 2 3
Frequency: Monthly
Table: 18-10-0004-01 (formerly CANSIM 326-0020)
Release date: 2023-10-17
Geography: Canada, Province or territory, Census subdivision, Census metr

Geography Products and product groups 3 5	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16
All-items	126.4	126.4	125.9	126.1	126.1	126.1
Food 6	132.4	133.8	131.3	132.6	132.4	132.2
Shelter 7	145	144.9	145.6	146.6	146.8	146.6
Household operations, furnishings and equipment	109.7	109.3	108.2	108.4	108.5	108.6
Clothing and footwear	97.1	97.1	99.5	100.4	103	101.8
Transportation	129.9	129	128.5	128.3	127	127.5
Gasoline	144	142.2	142.3	142.3	139.6	137.7
Health and personal care	124.8	126.3	121.5	122.3	123	123.3
Recreation, education and reading	98.9	98.7	99.1	97.6	97.6	97.5
Alcoholic beverages, tobacco products and recreational cannabis	155.7	156.7	156.6	156.5	156.7	156.7
All-items excluding food and energy 8	123	122.9	122.5	122.3	122.4	122.6
All-items excluding energy 8	124.9	125.1	124.3	124.3	124.4	124.5
Energy 8	140.2	139	141.3	143.5	142.4	140.8
Goods 9	115.7	116	115.2	116.2	116.3	115.9
Services 10	138.5	138.2	138	137.5	137.4	137.7

Consumer Price Index, monthly, not seasonally adjusted 1 2 3
Frequency: Monthly
Table: 18-10-0004-01 (formerly CANSIM 326-0020)
Release date: 2023-10-17
Geography: Canada, Province or territory, Census subdivision, Census metr

Geography Products and product groups 3 5	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17
All-items	126.9	127	127.5	127.6	127.8	127.3
Food 6	131.5	131.3	132.5	132.8	133.8	133.4
Shelter 7	147.1	146.7	146.9	147.5	147.1	146.9
Household operations, furnishings and equipment	108.6	108.5	108	108.5	109.5	109.2
Clothing and footwear	99.7	99.7	100	101.1	101.1	97.9
Transportation	131.5	131.9	131.2	131.1	131.1	130.2
Gasoline	145.9	146.7	146.7	146.5	144.1	139.9
Health and personal care	125.1	123.9	125	126.5	125.9	125.6
Recreation, education and reading	98.2	99	102	100.2	100	100.4
Alcoholic beverages, tobacco products and recreational cannabis	156.8	157	157.3	157.4	159.2	159.4
All-items excluding food and energy 8	123.4	123.5	124	123.9	124.3	124
All-items excluding energy 8	125.1	125.2	125.7	125.8	126.2	125.9
Energy 8	145.5	145.1	145.5	146.1	143.2	141
Goods 9	117	116.7	117.3	117.4	117	116
Services 10	138.3	138.8	139.2	139.3	140.2	140.3

Consumer Price Index, monthly, not seasonally adjusted 1 2 3
Frequency: Monthly
Table: 18-10-0004-01 (formerly CANSIM 326-0020)
Release date: 2023-10-17
Geography: Canada, Province or territory, Census subdivision, Census metr

Geography Products and product groups 3 5	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17
All-items	127.2	126.6	127.3	127.3	129	128.8
Food 6	134	132.6	131.9	131	133.1	132.1
Shelter 7	146.2	147.3	148.4	149	150.5	151.6
Household operations, furnishings and equipment	108.5	108.2	107	107.4	108.7	107.9
Clothing and footwear	98.3	96.1	98.9	100.8	102.3	100.5
Transportation	129.2	127.9	128.9	129.2	133	133.8
Gasoline	136.8	131.5	140	134.4	150.8	147.8
Health and personal care	126.4	127.6	126.8	126.4	126.6	125.5
Recreation, education and reading	100.9	99.8	101.9	100.7	100.7	99.4
Alcoholic beverages, tobacco products and recreational cannabis	163.4	163.6	163.7	164.1	163.8	163.8
All-items excluding food and energy 8	124	123.5	123.8	124.2	124.8	124.7
All-items excluding energy 8	126	125.4	125.5	125.7	126.6	126.3
Energy 8	137.5	137.6	144.8	143.1	154.6	154.3
Goods 9	115.5	114.6	116.2	116.1	119.2	118.6
Services 10	140.5	140.3	140	140.2	140.3	140.4

Consumer Price Index, monthly, not seasonally adjusted 1 2 3
Frequency: Monthly
Table: 18-10-0004-01 (formerly CANSIM 326-0020)
Release date: 2023-10-17
Geography: Canada, Province or territory, Census subdivision, Census metr

Geography Products and product groups 3 5	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18
All-items	128.9	129.5	130	130.4	130.6	131
Food 6	132.6	132.7	132.1	132	130.9	130.7
Shelter 7	152.4	153	152.6	152.9	153.6	153.9
Household operations, furnishings and equipment	107.4	107.3	107.6	109	107.8	107.4
Clothing and footwear	98.2	98.5	100.2	104	103.8	103.1
Transportation	134.1	134.9	134.5	136	137.5	140.3
Gasoline	144.2	144.2	144.2	155.4	169	172
Health and personal care	128.5	128	129.7	128.9	127.1	127
Recreation, education and reading	98.7	100.4	103.6	100.6	101.8	101
Alcoholic beverages, tobacco products and recreational cannabis	165.3	165.4	166.6	171	171.8	171.5
All-items excluding food and energy 8	124.8	125.4	126.4	126.3	126	126.5
All-items excluding energy 8	126.5	127	127.7	127.6	127.2	127.6
Energy 8	153.8	155	153.8	159.6	167.1	167.8
Goods 9	118.5	118.9	119.3	120.4	120.1	120.3
Services 10	140.8	141.6	142.3	141.9	142.6	143.2

Consumer Price Index, monthly, not seasonally adjusted 1 2 3
Frequency: Monthly
Table: 18-10-0004-01 (formerly CANSIM 326-0020)
Release date: 2023-10-17
Geography: Canada, Province or territory, Census subdivision, Census metr

Geography Products and product groups 3 5	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18
All-items	131.9	131.6	130.5	131	130.9	131.4
Food 6	132.3	130.9	129.7	128.9	132.5	132.2
Shelter 7	153.4	153.7	154.1	155.2	156.1	156.8
Household operations, furnishings and equipment	107.5	107.5	107.5	108.2	108.5	108.3
Clothing and footwear	101.5	101	101	101	97.1	98.9
Transportation	143.3	142.5	137.6	139.6	138.4	139.9
Gasoline	172	172	171	171.8	166.7	148.3
Health and personal care	127.4	129.1	127	126.4	125.3	127
Recreation, education and reading	102.4	102	102.7	101.6	99.9	99.4
Alcoholic beverages, tobacco products and recreational cannabis	173.1	173.2	173.4	173.6	174.1	173.3
All-items excluding food and energy 8	127.5	127.3	126.1	126.5	125.9	127.7
All-items excluding energy 8	128.7	128.3	127.1	127.4	127.3	128.9
Energy 8	166.6	167.1	167	169.9	169.3	157.7
Goods 9	120.3	119.9	119.7	120.3	120.7	119.2
Services 10	145.3	145	143	143.2	142.6	145.4

Consumer Price Index, monthly, not seasonally adjusted 1 2 3
Frequency: Monthly
Table: 18-10-0004-01 (formerly CANSIM 326-0020)
Release date: 2023-10-17
Geography: Canada, Province or territory, Census subdivision, Census metr

Geography Products and product groups 3 5	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19
All-items	130.9	131.1	131.6	132.2	132.9	134.1
Food 6	133.6	133	133.5	132.9	135.1	134.8
Shelter 7	155.9	156.2	156.8	158.5	158.9	161.8
Household operations, furnishings and equipment	109.2	109.4	109.2	109.4	109	108.8
Clothing and footwear	98.9	98	99.4	98.8	95.4	100.7
Transportation	136.6	137.7	138.7	139.7	141	141.7
Gasoline	148.3	148.3	154.1	163.7	163.5	163.5
Health and personal care	126.9	126.2	126	127.4	128.8	128.3
Recreation, education and reading	98.9	99.7	99.8	100.6	102.4	103.3
Alcoholic beverages, tobacco products and recreational cannabis	173.7	174	174.1	175.9	175.1	175.7
All-items excluding food and energy 8	127.1	127.5	127.7	128	128.3	129.9
All-items excluding energy 8	128.6	128.8	129	129.2	129.9	131.1
Energy 8	154.1	154.2	157.9	165.8	166.4	166.2
Goods 9	119.7	119.8	120.4	121.2	121.3	121.8
Services 10	143.7	144	144.4	144.9	146.2	148.2

Consumer Price Index, monthly, not seasonally adjusted 1 2 3
Frequency: Monthly
Table: 18-10-0004-01 (formerly CANSIM 326-0020)
Release date: 2023-10-17
Geography: Canada, Province or territory, Census subdivision, Census metr

Geography Products and product groups 3 5	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19
All-items	135.1	134.8	133.5	133.9	133.9	134.8
Food 6	135.5	134.1	133.7	133	135.1	135
Shelter 7	162.5	162.4	162.7	163.6	164.1	164.8
Household operations, furnishings and equipment	108.3	108	107.8	108.6	107.9	107.7
Clothing and footwear	101.6	99.6	99.1	99.5	99.3	98.2
Transportation	144.8	145.7	140	141.3	141.5	145.9
Gasoline	169	169.6	169.5	169.6	169.6	169.4
Health and personal care	129.5	128.8	128	128.8	127.7	127.8
Recreation, education and reading	104.8	103.7	103.6	102.4	100.7	99.9
Alcoholic beverages, tobacco products and recreational cannabis	175.7	175.8	176.3	176.5	176.2	176.4
All-items excluding food and energy 8	130.8	130.6	129.1	129.6	129.2	130.1
All-items excluding energy 8	132	131.6	130.3	130.6	130.6	131.3
Energy 8	170.2	169.7	169.5	170.8	171.5	173.7
Goods 9	122.6	121.6	121.4	122.1	122.6	122.4
Services 10	149.5	149.9	147.5	147.4	146.9	149

Consumer Price Index, monthly, not seasonally adjusted 1 2 3
Frequency: Monthly
Table: 18-10-0004-01 (formerly CANSIM 326-0020)
Release date: 2023-10-17
Geography: Canada, Province or territory, Census subdivision, Census metr

Geography Products and product groups 3 5	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20
All-items	135.8	135.9	135.1	133.6	133.1	134.3
Food 6	135.5	134.6	135	131.9	132.1	131.1
Shelter 7	169.4	169.1	168.5	167.1	165.1	165.8
Household operations, furnishings and equipment	107.4	107.4	108	107.4	105.9	106.6
Clothing and footwear	102.3	102.6	102.6	102	100.5	102.2
Transportation	144.1	145	140.8	138.4	139.4	142.7
Gasoline	169.6	169.1	149	120	122.4	137
Health and personal care	127.6	128.4	129.5	129.8	128.1	127.7
Recreation, education and reading	100.7	101.4	100.9	99.9	101.2	103
Alcoholic beverages, tobacco products and recreational cannabis	176.8	177.2	176.6	177.1	177.2	177.7
All-items excluding food and energy 8	130.5	131	130.7	130.8	130.6	131.6
All-items excluding energy 8	131.8	132	131.9	131.4	131.3	132
Energy 8	183	181.6	171	154.8	149.4	157.1
Goods 9	125	124.7	123.3	120.4	119.3	120.6
Services 10	148.1	148.7	148.6	148.8	149.1	150

Consumer Price Index, monthly, not seasonally adjusted 1 2 3
Frequency: Monthly
Table: 18-10-0004-01 (formerly CANSIM 326-0020)
Release date: 2023-10-17
Geography: Canada, Province or territory, Census subdivision, Census metr

Geography Products and product groups 3 5	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20
All-items	134.2	133.6	133.9	134.5	134.8	134.9
Food 6	132	129.5	131	131.3	132.6	131.9
Shelter 7	166.4	167.2	167.2	167.7	167.9	168
Household operations, furnishings and equipment	106.5	107	107.8	109.6	109.8	108.9
Clothing and footwear	101	98.4	101.6	104	103.3	102.4
Transportation	141.5	139.4	137.6	138.5	139.3	140.8
Gasoline	142.4	142.4	142.3	142.4	142.4	142.4
Health and personal care	127.5	128.9	129.2	131.1	130.5	130.5
Recreation, education and reading	103.4	103.4	104.4	101.8	101.3	101.9
Alcoholic beverages, tobacco products and recreational cannabis	177.6	177.6	177.8	177.8	177.5	177.5
All-items excluding food and energy 8	131	130.7	130.9	131.4	131.4	131.6
All-items excluding energy 8	131.6	130.9	131.3	131.8	132.1	132.1
Energy 8	161.8	161.8	161.3	162	163.5	164.8
Goods 9	120.9	119.7	120.8	121.7	122.2	121.9
Services 10	149.5	149.5	149	149.2	149.2	149.7

Consumer Price Index, monthly, not seasonally adjusted 1 2 3
Frequency: Monthly
Table: 18-10-0004-01 (formerly CANSIM 326-0020)
Release date: 2023-10-17
Geography: Canada, Province or territory, Census subdivision, Census metr

Geography Products and product groups 3 5	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21
All-items	136.1	136.4	136.6	137.8	138	138.5
Food 6	132.8	133	131.1	132.8	133.3	134
Shelter 7	170.2	170.3	171.4	171.7	171.2	171.9
Household operations, furnishings and equipment	109.6	110.5	109	110.2	108.7	109.7
Clothing and footwear	102.8	102.9	103.1	103.9	104	105.6
Transportation	142.7	143.5	145.6	147.8	148.4	148.2
Gasoline	147.4	150.9	157.7	165.9	168.1	172
Health and personal care	130.5	130.3	130.2	132.3	131.9	131.6
Recreation, education and reading	102.7	102.2	102.4	103.3	105.4	105.9
Alcoholic beverages, tobacco products and recreational cannabis	177.9	177.9	178	179.2	180.2	180.2
All-items excluding food and energy 8	132.6	132.8	132.8	133.7	133.7	134.1
All-items excluding energy 8	133.1	133.2	133	134	134.1	134.6
Energy 8	169	171.6	177.7	182.6	182.6	185.1
Goods 9	123.5	124.3	124.3	125.9	126.5	127.6
Services 10	150.5	150.2	150.6	151.4	151.1	150.8

Consumer Price Index, monthly, not seasonally adjusted 1 2 3
Frequency: Monthly
Table: 18-10-0004-01 (formerly CANSIM 326-0020)
Release date: 2023-10-17
Geography: Canada, Province or territory, Census subdivision, Census metr

Geography Products and product groups 3 5	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21
All-items	139.8	140.3	140.5	141.1	140.3	140.8
Food 6	135.1	134.3	135.1	135.5	134.9	134.5
Shelter 7	175.1	174.6	175.2	175.6	175.5	176.6
Household operations, furnishings and equipment	110.5	110.9	111.7	111.5	111.3	111.6
Clothing and footwear	106.3	105.3	105	105.2	105.3	103.9
Transportation	149.3	155.7	153	152.5	152	157.6
Gasoline	176.7	183.4	184.8	185	185	185
Health and personal care	133.1	132.7	132.6	133.6	132.9	133.4
Recreation, education and reading	106.1	106.1	106.5	108.6	105.9	104.1
Alcoholic beverages, tobacco products and recreational cannabis	180.7	181.3	181.5	181.5	182	182.3
All-items excluding food and energy 8	135.4	136.1	136	136.4	135.6	136.2
All-items excluding energy 8	135.8	136.3	136.3	136.7	135.9	136.3
Energy 8	187.5	188.7	191.3	194	193.7	195.7
Goods 9	128.5	128.4	129	129.9	129.8	129.7
Services 10	152.7	154	153.7	153.8	152.2	153.4

Consumer Price Index, monthly, not seasonally adjusted 1 2 3
Frequency: Monthly
Table: 18-10-0004-01 (formerly CANSIM 326-0020)
Release date: 2023-10-17
Geography: Canada, Province or territory, Census subdivision, Census metr

Geography Products and product groups 3 5	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22
All-items	141.1	142.5	144.9	145.8	147.9	149.2
Food 6	136.1	138	140.4	140.5	141.6	141.5
Shelter 7	178.7	179.4	182.6	182.8	184.5	184.3
Household operations, furnishings and equipment	110.5	112	114.7	116	116.8	117
Clothing and footwear	104.2	103.7	104.5	106.4	106.6	106.9
Transportation	154.3	155.9	160.6	163	166.2	171.4
Gasoline	186.5	195.1	209.9	216.8	239.7	257.3
Health and personal care	133.6	132.7	132.9	137.2	136.4	136.8
Recreation, education and reading	104.7	107.2	108.7	108.9	113.4	117.7
Alcoholic beverages, tobacco products and recreational cannabis	182.9	182.6	182.7	182.7	185.4	181.4
All-items excluding food and energy 8	136.1	137	138.3	139.1	140.6	142
All-items excluding energy 8	136.6	137.6	139.1	139.9	141.3	142.4
Energy 8	197.3	204.2	223.5	225.9	240.7	246.1
Goods 9	130.2	132.2	136.3	136.9	139.4	140.1
Services 10	153.5	153.9	154.3	155.4	157	159.2

Consumer Price Index, monthly, not seasonally adjusted 1 2 3
Frequency: Monthly
Table: 18-10-0004-01 (formerly CANSIM 326-0020)
Release date: 2023-10-17
Geography: Canada, Province or territory, Census subdivision, Census metr

Geography Products and product groups 3 5	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22
All-items	150.6	151	151	151.8	152	152.2
Food 6	143.9	146	147	146.1	149.3	150.6
Shelter 7	184.3	187.7	188.8	190.8	192.8	193
Household operations, furnishings and equipment	116.6	116.6	116.6	117.5	116.4	117.5
Clothing and footwear	106.6	109.5	108.3	109.1	108.7	108.1
Transportation	175.5	171.4	169.5	171.8	169.2	169.8
Gasoline	247.1	221.2	220.8	237	220.9	206.9
Health and personal care	138.4	139.5	138.2	139.6	140.8	141.3
Recreation, education and reading	120	117.9	117	117.4	115.3	113.3
Alcoholic beverages, tobacco products and recreational cannabis	181.8	181.9	182.7	183.1	184.1	185.1
All-items excluding food and energy 8	143.6	144.6	144.2	144.9	144.4	144.9
All-items excluding energy 8	144.1	145.3	145.2	145.6	145.8	146.5
Energy 8	240.9	227.4	227.5	237.4	237	227.7
Goods 9	140.2	139.3	139.7	141.3	141.8	141.5
Services 10	162.2	164.3	163.6	163.6	163.3	164.1

Consumer Price Index, monthly, not seasonally adjusted 1 2 3
Frequency: Monthly
Table: 18-10-0004-01 (formerly CANSIM 326-0020)
Release date: 2023-10-17
Geography: Canada, Province or territory, Census subdivision, Census metr

Geography Products and product groups 3 5	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23
All-items	152.3	152.5	152.9	154.2	154.9	156.4
Food 6	151.2	151.1	151.6	152.6	155	156
Shelter 7	195.5	195.5	195.2	197	197	196.6
Household operations, furnishings and equipment	117.3	114.3	115.7	116.2	114.1	112.2
Clothing and footwear	108.7	110.1	110.2	110.8	110.8	109.5
Transportation	165	163.9	165.2	167.9	166.9	171.5
Gasoline	201.2	199	200.7	217.1	218.1	218.2
Health and personal care	142.4	141.7	142.6	144.5	147.8	148.4
Recreation, education and reading	112.8	115.5	115.8	116.2	119.1	125.3
Alcoholic beverages, tobacco products and recreational cannabis	187.1	188.8	188.9	189.7	192.6	192.5
All-items excluding food and energy 8	145.3	145.7	146.3	146.9	147.5	149.1
All-items excluding energy 8	146.9	147.2	147.8	148.5	149.4	151
Energy 8	223.3	220.3	218.4	228.4	226.8	225.8
Goods 9	141.6	141.3	142.2	144.2	145.2	145.4
Services 10	164.3	164.9	164.9	165	165.7	168.5

Consumer Price Index, monthly, not seasonally adjusted 1 2 3
Frequency: Monthly
Table: 18-10-0004-01 (formerly CANSIM 326-0020)
Release date: 2023-10-17
Geography: Canada, Province or territory, Census subdivision, Census metr

Geography	
Products and product groups 3 5	Jul-23
All-items	158.4
Food 6	156.5
Shelter 7	199
Household operations, furnishings and equipment	112.2
Clothing and footwear	110.9
Transportation	176.6
Gasoline	218.2
Health and personal care	147.9
Recreation, education and reading	128.9
Alcoholic beverages, tobacco products and recreational cannabis	192.7
All-items excluding food and energy 8	151.6
All-items excluding energy 8	153
Energy 8	223.7
Goods 9	145.1
Services 10	172.7

Footnotes:

1 The Consumer Price Index (CPI) is not a cost-of-living index. The objective behind a cost-of-living index is to measure changes in expenditures necessary for consumers to maintain a constant standard of living. The idea is that consumers would normally switch between products as the price relationship of goods changes. If, for example, consumers get the same satisfaction from drinking tea as they do from coffee, then it is possible to substitute tea for coffee if the price of tea falls relative to the price of coffee. The cheaper of the interchangeable products may be chosen. We could compute a cost-of-living index for an individual if we had complete information about that person's taste and spending habits. To do this for a large number of people, let alone the total population of Canada, is impossible. For this reason, regularly published price indexes are based on the fixed-basket concept rather than the cost-of-living concept.

2 This table replaces table 18-10-0008-01 which was archived with the release of April 2007 data.

3 From April 2020 to November 2021, and from January 2022 to February 2022, certain sub-indexes and components thereof were imputed using special approaches in either one, or more months. The affected indexes include child care services; housekeeping services; air transportation; personal care services; recreational services; travel tours; spectator entertainment; use of recreational facilities and services; beer served in licensed establishments; wine served in licensed establishments, and liquor served in licensed establishments. The details of these treatments from April 2020 to March 2021 are provided in technical supplements available through the Prices Analytical Series (opens new window). Starting in April 2021

4 The relatively small size of the housing market in these two cities makes it difficult to construct reliable price indexes for new houses. To compensate, the price movements of rental accommodation are used to approximate the price movements of new houses. The rent information itself is collected using different pricing frequencies and collection methods than in the rest of the country. Because of these problems, the indexes for rented accommodation, and owned accommodation are not published for these two cities. Further, the all-items indexes published for these two cities are not strictly comparable with the same indexes for the provinces or the other 16 cities.

The goods and services that make up the Consumer Price Index (CPI) are organized according to a hierarchical structure with the all-items CPI as the top level. Eight major components of goods and services make up the all-items CPI. They are food; shelter; household operations, furnishings and equipment; clothing and footwear; transportation; health and personal care; recreation, education and reading; and alcoholic beverages, tobacco products and recreational cannabis. These eight components are broken down into a varying number of sub-
5 groups which are in turn broken down into other sub-groups. Indents are used to identify the components that make up each level of aggregation. For example, the eight major components appear with one indent relative to the all-items CPI to show that they are combined to obtain the all-items CPI. NOTE: Some items are recombined outside the main structure of the CPI to obtain special aggregates such as all-items excluding food and energy; energy; goods; services; or fresh fruit and vegetables. They are listed after the components of the main structure of the CPI following the last major component entitled alcoholic beverages, tobacco products and recreational cannabis.

6 Food includes non-alcoholic beverages.

Part of the increase first recorded in the shelter index for Yellowknife for December 2004 inadvertently reflected rent increases that actually occurred earlier. As a result, the change in the shelter index was overstated in December 2004, and was understated in the
7 previous two years. The shelter index series for Yellowknife has been corrected from December 2002. In addition, the Yellowknife all-items Consumer Price Index (CPI) and some Yellowknife special aggregate index series have also changed. Data for Canada and all other provinces and territories were not affected.

8 The special aggregate energy includes electricity; natural gas; fuel oil and other fuels; gasoline; and fuel, parts and accessories for recreational vehicles.

Goods are physical or tangible commodities usually classified according to their life span into non-durable goods, semi-durable goods and durable goods. Non-durable goods are those goods that can be used up entirely in less than a year, assuming normal usage. For example, fresh food products, disposable cameras and gasoline are non-durable goods. Semi-durable goods are those goods that may last less than
9 12 months or greater than 12 months depending on the purpose to which they are put. For example, clothing, footwear and household textiles are semi-durable goods. Durable goods are those goods which may be used repeatedly or continuously over more than a year, assuming normal usage. For example, cars, audio and video equipment and furniture are durable goods.

A service in the Consumer Price Index (CPI) is characterized by valuable work performed by an individual or organization on behalf of a consumer, for example, car tune-ups, haircuts and city public transportation. Transactions classified as a service may include the cost of goods by their nature. Examples include food in restaurant food services and materials in clothing repair services.

YUKON UTILITIES BOARD

IN THE MATTER OF the *Public Utilities Act*

and

Review of Yukon Utilities Board Order 2022-03

BEFORE:	R. Buchan, Chair	)	January 9, 2023
	B. King, Vice-Chair	)	
	A. Fortin	)	
	L. McCullough	)	

BOARD ORDER 2023-01

WHEREAS:

A. On March 16, 2022, the Yukon Utilities Board (Board) issued Board Order 2022-03 in relation to Yukon Energy Corporation's (YEC) 2021 General Rate Application (GRA). In Appendix A to Board Order 2022-03: Reasons for Decision, the Board made findings on the GRA;

B. On April 14, 2022, Yukon Energy Corporation filed an Application for Review and Variance of Board Order 2022-03 (Review Application), pursuant to section 62 of the *Public Utilities Act* (Act) and section 31 of the Board's Rules of Practice (Rules);

C. On August 26, 2022, the Board issued Board Order 2022-10 granting YEC's Review Application in part on the initial screening phase. Accordingly, the Board directed that the Review Application proceed to Phase 2 on the limited issue of determining the amount of the risk premium reduction and whether the reduction should be greater than zero but not more than 50 basis points;

D. The Board issued a process schedule for Phase 2 of the Review Application in Board Order 2022-12 on September 6, 2022; and

E. The Board closed the record for this proceeding on November 3, 2022.

NOW THEREFORE, for the reasons set out in Appendix A to this Order**,** the Board orders the following**:**

1. YEC's return on equity for its 2021 General Rate Application is hereby set at 8.65 percent.
2. YEC shall submit a compliance filing (filing for acknowledgement) to the Board by February 8, 2023, in accordance with the directions set out in the attached Reasons for Decision (Appendix A).

DATED at the City of Whitehorse, Yukon, this 9th day of January 2023.

BY ORDER

Richard Buchan
Chair

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Introduction

The 2023–24 Fiscal and Economic Outlook presents the territory's current fiscal and economic position and expectations for the medium term. The Government of Yukon is moving the territory toward a sustainable and prosperous future while ensuring responsible fiscal management across all government programs and services. The Yukon is recovering from the impacts of the pandemic and the economic outlook is positive.

Despite the recent challenges created by higher rates of inflation, expectations are that the Yukon will build on 2022's robust economic growth, with further real Gross Domestic Product (GDP) gains and an outlook highlighted by a strong labour market and additional population growth. The government remains committed to working closely with partners in the public and private sectors, including First Nations governments, to ensure a strong, diversified and sustainable economy for all Yukoners. Overall, the territory's economy is well-positioned to address the challenges ahead and continue growing in the coming years.

Part 1: The Yukon's finances

In the 2023–24 Budget, the Yukon government is delivering on its longstanding commitment to growing the economy while ensuring strong, sustainable fiscal management. The government projects a surplus of $48.2 million in 2023–24 and projects to remain in a surplus position throughout the duration of this fiscal outlook. A surplus of 2-3 per cent of the total budget is a prudent fiscal management tool and demonstrates the ability of the government to address unforeseen events without going into deficit. Maintaining a surplus position lessens the government's potential need to borrow funds and reduces the net debt position. The expected fiscal position in 2023–24 reflects a focus on strategically allocating resources to the ongoing priorities of Yukoners.

Table 1. Fiscal summary

($ millions)	2022–23 Main Estimates	2022–23 Supplementary Estimates #2	2023–24 Main Estimates	2024–25 Plan	2025–26 Plan
Revenue[1,2]	1,460.2	1,504.5	1,575.4	1,663.5	1,719.2
Expense[3]	(1,644.6)	(1,683.8)	(1,642.4)	(1,716.5)	(1,769.1)
Contingency for Anticipated Expenses	(10.0)	(10.0)	(50.0)	(50.0)	(50.0)
Accounting Adjustments[4]	233.9	233.2	165.2	161.7	144.9
Surplus/(Deficit)[5]	39.5	43.9	48.2	58.8	45.1
Net Financial Assets/(Debt), end of year[6]	(207.5)	(298.5)	(374.8)	(453.0)	(528.0)

Source: Department of Finance. Numbers may not add due to rounding.

1. To align with the presentation in the Yukon's Public Accounts, revenues and recoveries do not include those collected by the Yukon Housing Corporation, which are included in the Accounting Adjustments in this table.

2. Figures for revenue, contingency for anticipated expenses and surplus (deficit) are found on Pages S-8 of the 2023–24 Main Estimates, and equivalent pages of budget documents for other periods.

3. Figures for expense and accounting adjustments are found on Pages S-18 of the 2023–24 Main Estimates and equivalent pages of budget documents for other periods.

4. Accounting Adjustments are the sum of "Tangible Capital Assets (net)," "Investment in Land Development," "Expenditures on Loan Programs," and "Other Adjustments (net)," on Page S-9 of the 2023–24 Main Estimates, and equivalent pages of budget documents for other periods.

5. Surplus/(Deficit) is the sum of Revenue, Expense, Contingency for Anticipated Expenses, and Accounting Adjustments.

6. Found on Page S-9 of the 2023–24 Main Estimates.

Net financial debt, or net debt as it is often known, is expected to increase by $76.3 million in 2023–24 to a total of $374.8 million. Recent increases to the government's net financial debt position were incurred to fund ongoing maintenance of the territory's infrastructure and to invest in new projects that will benefit Yukoners now and well into the future. In standard accounting, net financial debt is a measure of how much the government would need to pay if all of its liabilities were due immediately. It does not mean government needs to borrow those funds. Most of the government's net debt position is for long-term liabilities that will not be realized all at once.

Part of the changes to net debt reflect a new accounting standard that came into effect in April 2022. These new rules require the government to record and measure future financial obligations to retire government assets from service, such as buildings or equipment, once they are no longer of productive use. The estimated future costs to retire an asset are then recognized over an asset's productive life. The increase to net debt from 2022–23 includes an additional $54.3 million to reflect accounting changes to align with the new standard. The new standard is also expected to increase net debt by approximately $1.6 million annually.

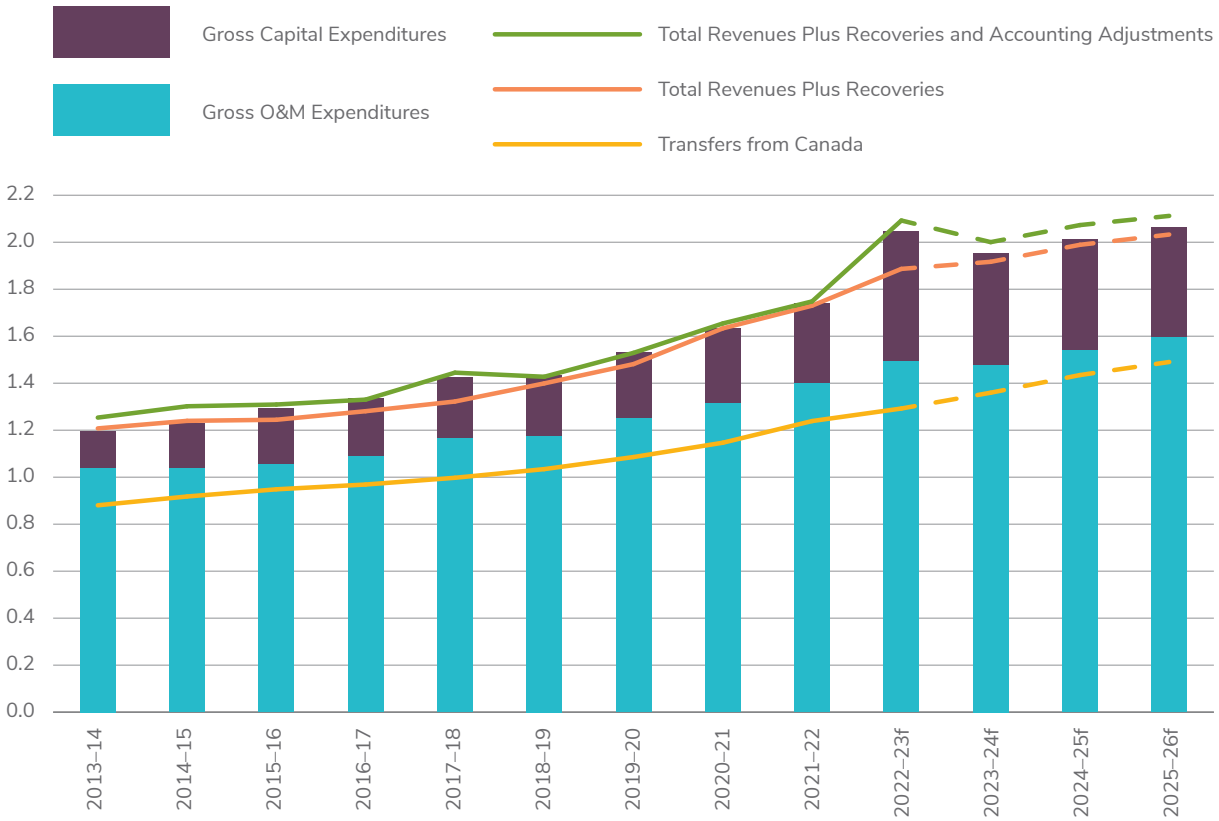
The government is committed to maintaining fiscal sustainability. To achieve this, the government has reviewed spending commitments to ensure expenditures are effectively being used within the framework of expected revenues. These measures will help to ensure that the government is able to meet its spending commitments while maintaining a healthy fiscal position. Capital expenditures are forecast to decrease by $35.2 million or 9.9 per cent, net of recoveries, from the 2022–23 Main Estimates to preserve the government's strong fiscal standing and address increasing inflation while continuing to invest in priority areas. The decrease to capital spending is partially offset by an increase to the forecast for Operations and Maintenance (O&M) expenditures of $33.0 million or 2.6 per cent, net of recoveries, from the 2022–23 Main Estimates.

The government's fiscal summary for 2023–24 also includes a $50 million contingency for areas of expected, but presently undefined, expenditures. The government has benefitted from this realistic approach to budgeting in recent years for COVID-19 spending and we are continuing this approach for expected cost pressures. These costs are not presented in departmental budgets in the coming fiscal year as the expenditures are not yet known. They are included in the overall financial framework so that they will not affect the Yukon's forecast fiscal position, should they be needed. This allows the government to remain transparent about potential pressures and would require legislative authority.

In Chart 1, forecast spending and revenue for the Yukon, including recoveries, from 2022–23 through 2025–26, are compared to historical spending as reported in the Yukon's Public Accounts. In recent fiscal years, growth in government spending has increased in line with revenue growth. For the fiscal years between 2013–14 and 2022–23, O&M expenditures have grown by 5.1 per cent annually and revenues have grown by 5.0 per cent annually, on average. For 2023–24 to 2025–26, expenditures and revenues are expected to change at a similar pace, with expenditures growing by an annual average of 2.3 per cent, while government revenues are expected to grow at an average of 2.5 per cent annually.

Chart 1. Government of Yukon fiscal indicators[7,8]

Expenditures and revenues ($ billions)



Source: Department of Finance *f = forecast*

7. Fiscal years 2013–14 to 2021–22 represent actuals as reported in the Yukon's Public Accounts. For comparability, forecasts for fiscal years 2022–23 to 2025–26 use the same methodology, which differs from the presentation in Table 1 above.

8. To align with the presentation in the Yukon's Public Accounts, revenues and recoveries do not include those collected by the Yukon Housing Corporation, which are netted-out of the gross expenditures presented in this chart.

Revenue

Government revenues rely heavily on transfers from the Government of Canada, supplemented by own-source revenues that are mostly driven by economic activity. The Yukon government's revenue is critical to ensuring that the government has the resources needed to meet its spending commitments. As shown in Table 2, total revenue, excluding recoveries, is expected to be $1.58 billion in 2023–24. This represents an increase of $70.9 million, or 4.7 per cent, from the most recent estimates in the 2022–23 Supplementary Estimates #2. This increase is primarily driven by the territory's economic position and a changing fiscal situation across Canada, which affects federal transfers.

Table 2. Revenue by type[9,10]

($ millions)	2022–23 Main Estimates	2022–23 Supplementary Estimates #2	2023–24 Main Estimates	2024–25 Plan	2025–26 Plan
Transfers from Canada	**1,244.4**	**1,261.4**	**1,327.0**	**1,400.3**	**1,454.7**
Tax revenue	**157.7**	**175.0**	**170.9**	**177.2**	**182.2**
Personal income tax	89.9	100.7	98.4	102.4	105.6
Corporate income tax	24.4	32.0	27.4	27.8	28.4
Property tax	7.0	7.0	7.2	7.6	7.7
Fuel oil tax	9.7	8.7	8.8	8.8	8.9
Tobacco and alcohol taxes	18.6	18.4	20.0	20.7	21.1
Insurance premium tax	8.1	8.2	9.0	9.9	10.6
Other revenue	**58.1**	**68.1**	**77.5**	**85.9**	**82.3**
Liquor profit	9.4	7.5	8.8	8.8	9.1
Licenses, fees, registrations and permits	17.6	17.1	18.3	18.7	19.2
Sale of land	19.2	20.8	32.3	34.2	31.3
Other revenue	12.0	22.8	18.1	24.2	22.6
Total revenue	**1,460.2**	**1,504.5**	**1,575.4**	**1,663.5**	**1,719.2**

Source: Department of Finance. Numbers may not add due to rounding.

9. All revenue figures are found on Pages S-14 and S-15 of the 2023–24 Main Estimates, and equivalent pages of budget documents for other periods.

10. To align with the presentation in the Yukon's Public Accounts, revenues do not include those collected by the Yukon Housing Corporation.

Transfers from Canada

Transfers from Canada, which includes the Territorial Formula Financing grant, represent about 84 per cent of the Yukon's total revenue in 2023–24. Territorial formula financing helps to reduce the gap between the Yukon's ability to raise revenue and its spending needs for core services.

The grant is responsive to changing economic and demographic circumstances in the territory compared to the rest of the country. This includes changes in public spending across the country, which are increasing due to the high inflationary environment and associated inflation relief programs. The growth in spending for other provinces and territories have an upward impact on the Yukon's Territorial Formula Financing grant. However, the improved outlook on the grant is being offset somewhat by growth in resource revenues. Resource revenues in the territory are expected to increase as royalties increase, which would have a downward impact on revenue from the Territorial Formula Financing grant. Under the Devolution Transfer Agreement with Canada, the Yukon's grant is reduced dollar for dollar of resource revenues in excess of $6 million in any given year. Resource revenues subject to offset were $10.2 million in 2021–22, meaning the grant in 2023–24 will be reduced by $4.2 million.

At the time that the 2023–24 Main Estimates were prepared, the Yukon government, along with other provinces and territories, were discussing increases to the Canada Health Transfer that could strengthen the healthcare system for the benefit of all Canadians. The Canada Health Transfer forms part of the overall transfers from Canada. Increases to the Canada Health Transfer have not yet been included in expected revenues for 2023–24.

Taxation revenue

The Yukon's own-source revenue from taxation is forecast to decrease in 2023–24 from the 2022–23 Supplementary Estimates #2. Personal and corporate taxation revenues are expected to be strong in 2023–24, but are forecast to be lower than current estimates for 2022–23 primarily due to a non-recurring adjustment for the 2021 tax year in 2022–23. Adjustments for prior tax years are common due to the timing of final reconciliations of tax assessment information. Corporate income tax projections for 2022–23 have been revised upward from stronger than expected corporate profits but are expected to return to trend in 2023–24.

Personal income tax revenues are expected to continue to be strong due to high inflation and the territory's strong labour market performance, which is increasing individual taxable incomes. Business performance continues to be strong in the territory, but corporate income tax revenue can see large variations from year-to-year. The outlook for corporate taxation, while still expected to increase, has also been reduced from projections in previous years due to a change in federal tax provisions that increases the scope of businesses eligible for the small business tax rate. In the Yukon, the small business tax rate is zero per cent.

The forecast for tax revenue from tobacco products has increased. The *Tobacco Tax Act* links changes to the tax rate to changes in the Consumer Price Index (CPI), so the tax rate increased from 31 cents to 32 cents per cigarette as of January 1, 2023. Under the current outlook for inflation, the tax rate for tobacco products is expected to increase to 37 cents per cigarette by the end of 2027.

Expectations for fuel tax revenue in 2023–24 are lower than in the 2022–23 Main Estimates. Fuel tax revenues have not returned to pre-pandemic levels, which could be partly explained by the tourism industry continuing to operate below levels experienced prior to the start of the pandemic. The ongoing outlook for fuel taxes is expected to be mostly flat as more Yukoners adopt electric vehicles and make other transportation choices that are consistent with the Yukon's *Our Clean Future* strategy.

Aside from changes to the tobacco tax, there are no changes to tax rates proposed as part of the 2023–24 budget.

Other revenue

In addition to transfers from Canada and taxation revenue, the government also generates revenue from other sources. These include liquor profit, licenses, fees, registrations, permits and proceeds from land sales. Revenue from these sources are expected to exceed recent levels, in part due to elevated revenue from land sales.

Operations and maintenance expense

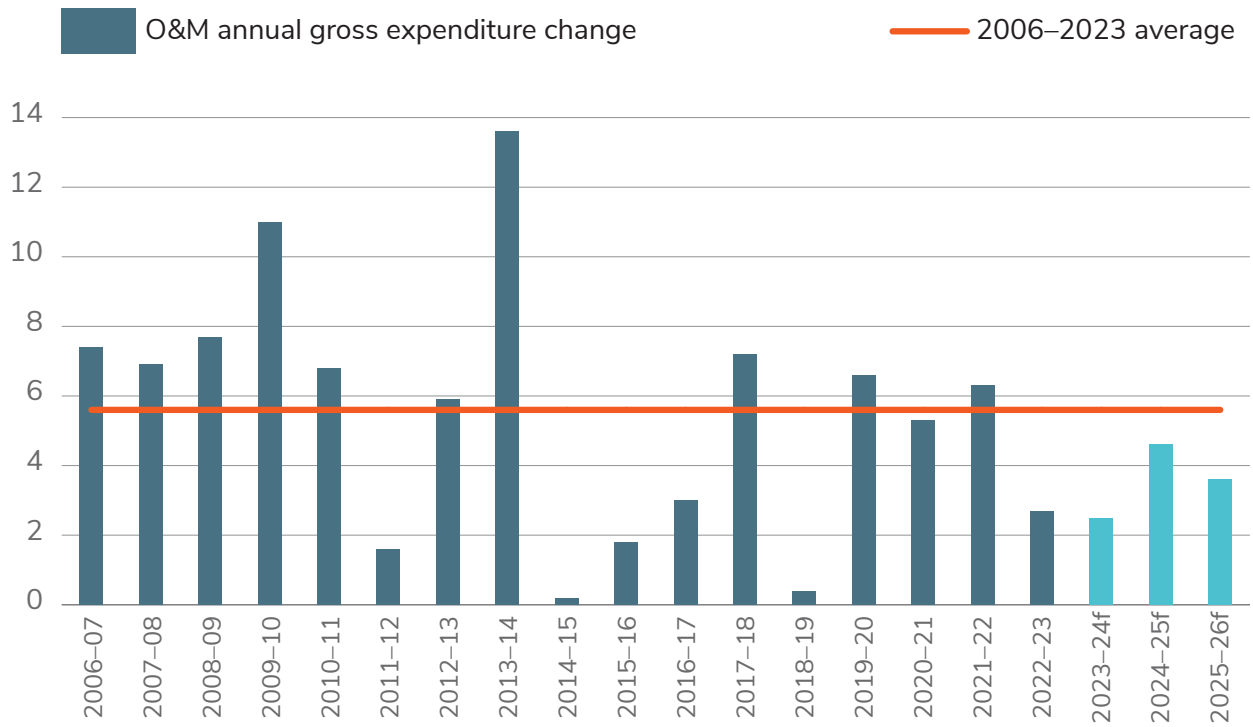
O&M spending for 2023–24 is budgeted at $1.45 billion, which reflects a $35 million, or 2.5 per cent, increase over the previous year's Main Estimates. The increase in spending is primarily for:

- making day-to-day life more affordable for Yukoners;
- investing in the Yukon's health and social system;
- addressing the substance use health emergency;
- improving sustainability and preserving the territory's environment;
- investing in housing and related services, particularly for the most vulnerable; and
- continuing to build relationships and foster reconciliation with Yukon First Nations.

Chart 2 compares forecast gross O&M spending from 2022–23 through 2025–26 to actual historical O&M spending as reported in the Yukon's Public Accounts. The average annual growth in O&M spending between 2006–07 and 2022–23 was 5.6 per cent. Forecast O&M spending growth in 2024–25 and 2025–26 is anticipated to remain below the average at approximately 4.5 per cent and 3.5 per cent, respectively.

Chart 2. Annual growth in O&M budgets

Change in Government of Yukon gross O&M spending (per cent)



Source: Department of Finance *f = forecast*

Higher rates of inflation continue to be the reality for Yukoners, and family budgets are becoming tighter. The government continues to take steps to provide targeted inflationary relief to families, especially the most vulnerable. The government continues to assess how inflation is impacting Yukoners. In 2023–24, the government is extending the Inflation Relief Rebate Program, which provides a $50 per month rebate on ATCO Electric and Yukon Energy utility bills for the April and May billing periods, along with an additional three months later in the year. Other measures in the 2023–24 Budget to help make life more affordable for Yukoners include funding for food in Yukon schools, the timber harvesting incentive to boost fuelwood supply, a quarterly top-up of $150 to eligible recipients of the Yukon Senior Income Supplement and a $100 monthly increase to eligible Social Assistance recipients.

With the COVID-19 State of Emergency coming to an end in March 2022, the Yukon is now adapting to living with the risks from COVID-19 while continuing to support Yukoners' well-being. However, healthcare systems across Canada, including the Yukon, continue to be strained following the pandemic. Healthcare workers are experiencing stress and burnout, and people seeking health services are experiencing long wait times due to staff shortages. The 2023–24 Budget includes funding to improve supports for critical staff, including recruitment and retention bonuses for nurses, negotiated increases with the Yukon Medical Association, a human resources strategy to improve health care worker recruitment and adding nursing positions in rural locations. The government also continues to act on the recommendations from the *Putting People First* report. This includes funding for the territory's dental plan, early learning and childcare.

In 2023–24, the government will continue to support the needs of individuals and communities impacted by the substance use health emergency. This includes additional funding to address the harms of substance use, combat the supply of harmful substances through additional RCMP supports, and help youth with substance use challenges. Together, these initiatives support people who are struggling with addiction and mental health issues and help to reduce the harm caused by substance use in communities.

Many areas across Canada are facing housing shortages and challenges with housing affordability. In 2023–24, the government will continue working to meet the housing needs of Yukoners, including partnering with the private sector on lease costs and supportive services for seniors at the new Normandy Living facility in Whitehorse. The Budget also includes funding to ensure the Yukon Housing Corporation's housing stock remains safe and well maintained.

The government remains fully committed to supporting reconciliation and respectful partnerships with Yukon First Nations governments. The government is working in partnership with Yukon First Nations on key priorities in 2023–24. This includes funding for Community Safety Officers and policing initiatives in communities, and support for the community safety planning priorities of Yukon First Nations governments in their communities.

The government continues to make progress on the implementation of *Our Clean Future* and protect the environment. The Yukon government is working in partnership with the Government of Canada to advance land use planning and species-at-risk protection in the Yukon through the *Bilateral Nature Agreement*. Through this, government will advance work towards the federal government's mandate to conserve and protect 25 per cent of land by 2025, and 30 per cent by 2030.

Five-Year Capital Plan update

With the 2023–24 Main Estimates, the Yukon government is publishing its sixth annual plan for its capital investment priorities over the next five years. The plan helps drive transparency, certainty and coordination with businesses, First Nations governments and municipalities.

Table 3. *Five-Year Capital Plan* gross expenditures by category

($millions)	2023–24	2024–25	2025–26	2026–27	2027–28	Totals
Climate change, energy and green economy	36	43	47	42	29	197
Land development, housing, education and health	133	84	78	81	93	470
Community and First Nations infrastructure	78	75	75	60	65	352
Transportation infrastructure	160	177	197	123	123	779
Real property and asset management	33	46	46	51	35	211
Information technology	45	51	18	17	14	146
Totals	484	475	462	374	359	2,155

Source: Capital Planning Office. Numbers may not add due to rounding.

The 2023–24 *Five-Year Capital Plan* includes approximately $2.15 billion in capital spending over the next five years. These investments will focus on improving access to stable and affordable housing, increasing accessibility to healthcare services, providing modern school facilities and advancing the territory's climate change goals. The government continues to leverage funding from the federal government and other partners to find offsets for over one-third of the capital spending in the plan.

The capital budget for 2023–24 is projected to be $483.8 million, a modest decrease from the 2022–23 Main Estimates. The government remains committed to robust and steady investments in the territory's infrastructure. However, it is prudent for the government to carefully consider how it is investing in capital projects to address increasing inflation by reducing previously planned capital spending in its *Five-Year Capital Plan*. The government has reviewed planned projects in the Plan to ensure it is maintaining its current assets while delivering on the new critical infrastructure that Yukoners need. For certain capital projects, the government is exploring innovative ways to deliver these projects, including partnering with municipalities or First Nations governments in the development of new infrastructure. This approach has resulted in a lower total spend in the next few years compared to earlier projections, while creating a more stable outlook for capital spending.

The government remains committed to robust and steady investments in the territory's infrastructure.

The government is making priority capital investments across six main areas in the 2023–24 *Five-Year Capital Plan*:

- $197 million for climate change, energy and green economy projects to continue to advance the *Our Clean Future* strategy and invest in sustainable jobs in the territory. In 2023–24, this includes investing in renewable energy projects, such as solar installations and biomass, through the Green Infrastructure Program; and helping Yukoners increase the energy efficiency of their homes and businesses through the Better Buildings energy retrofit loans program.
- $470 million for land development, housing, education and health projects to ensure the territory can meet the housing, educational and healthcare needs of a growing population and economy. In 2023–24, this includes completing the Old Crow 10-unit mixed-use housing project and work on the Kêts'ádań Kų School in Burwash Landing.
- $352 million for community and First Nations infrastructure to meet infrastructure needs in communities across the territory, including working in partnership with Yukon First Nations and municipal governments on their priorities. In 2023–24, this includes work on a new Fire Hall building in Carmacks; upgrades to the existing Public Works building in Carmacks; and upgrades to the Teslin Tlingit Council community hub.
- $779 million for transportation infrastructure to invest in the territory's transportation system to keep Yukoners and the economy moving and advance the sustainability of supply chains critical to the Yukon. In 2023–24, this includes ongoing work on critical components of the Yukon's transportation infrastructure like the Nisutlin Bay Bridge project, Erik Nielsen Whitehorse International Airport runways and upgrades to the North Klondike Highway.
- $211 million for real property and asset management projects to build and maintain assets that are essential to the delivery of government services. In 2023–24, this includes continuing to retrofit the Old Territorial Administration Building in Dawson City and work on conceptual designs for potential expansions and recreational activities at several campgrounds across the territory.
- $146 million for information technology projects to enhance the territory's vital technological links to Canada and the world. In 2023–24, work will continue on the Dempster Fibre project, which will provide redundancy, increase reliability and reduce the risk of outages in the territory's critical telecommunications infrastructure.

In recent years, the government has made substantial capital investments to help sustain and build upon critical infrastructure for the benefit of Yukoners now and for generations to come.

Some important recently-completed projects include:

- $22 million, along with funding from Canada, for the Mayo to McQuesten Transmission Line replacement project, which came online in 2021 and is improving the quality and reliability of electricity infrastructure in the area;
- $22 million, in partnership with Canada, for the Faro Public Works & Fire Hall Building and the Watson Lake Municipal Services Building, which combine public works and fire services into a single shared space, saving money on both construction and long-term operating costs; and
- $21 million for the 47-unit residential housing complex at 401 Jeckell Street, completed in January 2023 in partnership with the Canada Mortgage and Housing Corporation. It is providing affordable homes of various sizes for low-income and vulnerable families, seniors and individuals.

In recent years, the government has made substantial capital investments to help sustain and build upon critical infrastructure for the benefit of Yukoners now and for generations to come.

Part 2: Economic overview

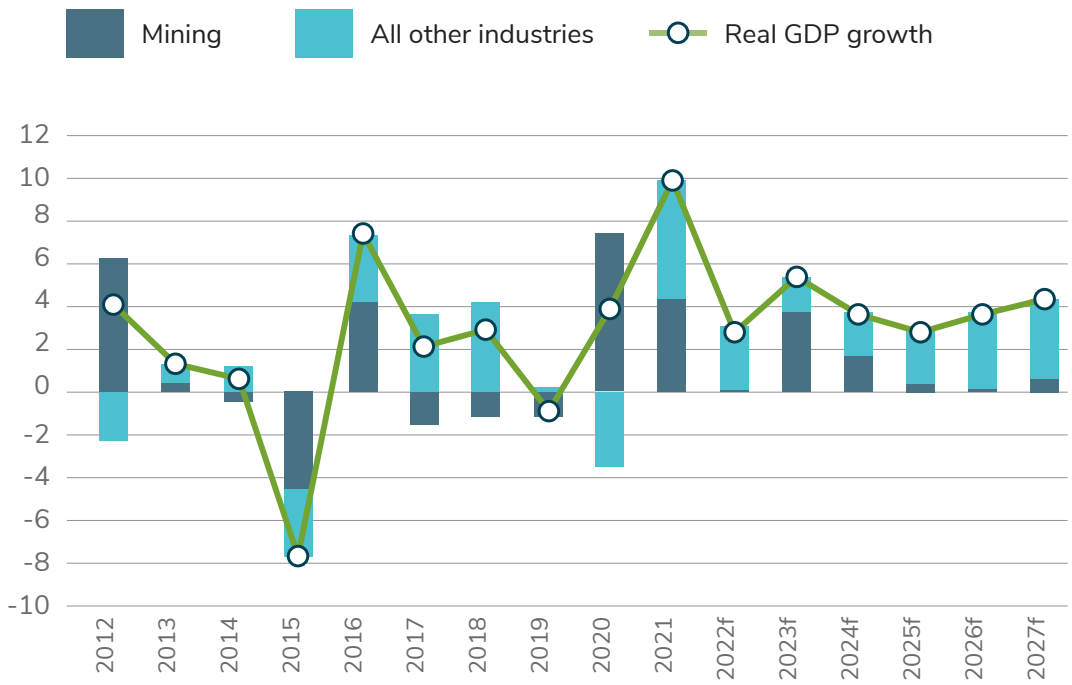
Positive outlook for real GDP growth

The outlook for the Yukon's economy remains positive. A strong labour market is leading to job growth and low unemployment. Tourism is coming back to the territory and the construction sector is busy. Inflation remains higher than anticipated but is expected to moderate with the stabilization of energy prices, improvements to global supply chains and an increase in interest rates that is beginning to absorb excess demand in the Canadian economy.

The Yukon's real GDP is expected to continue to expand. The Yukon led the country in real GDP growth in both 2020 and 2021, with 2021's increase of 10 per cent being the strongest in 13 years. The pace of this expansion returned to more normal levels in 2022 with estimated real GDP growth of 3.1 per cent, close to the Canadian growth estimate of 3.5 per cent. Last year's performance was impacted primarily by the mining sector with disruptions at the Eagle Gold mine and a temporary suspension of operations at the Keno Hill mine.

Chart 3. Further gains in real GDP expected in all years of the forecast

Contribution to real GDP growth (percentage points)



Source: Statistics Canada, Department of Finance *f = forecast*

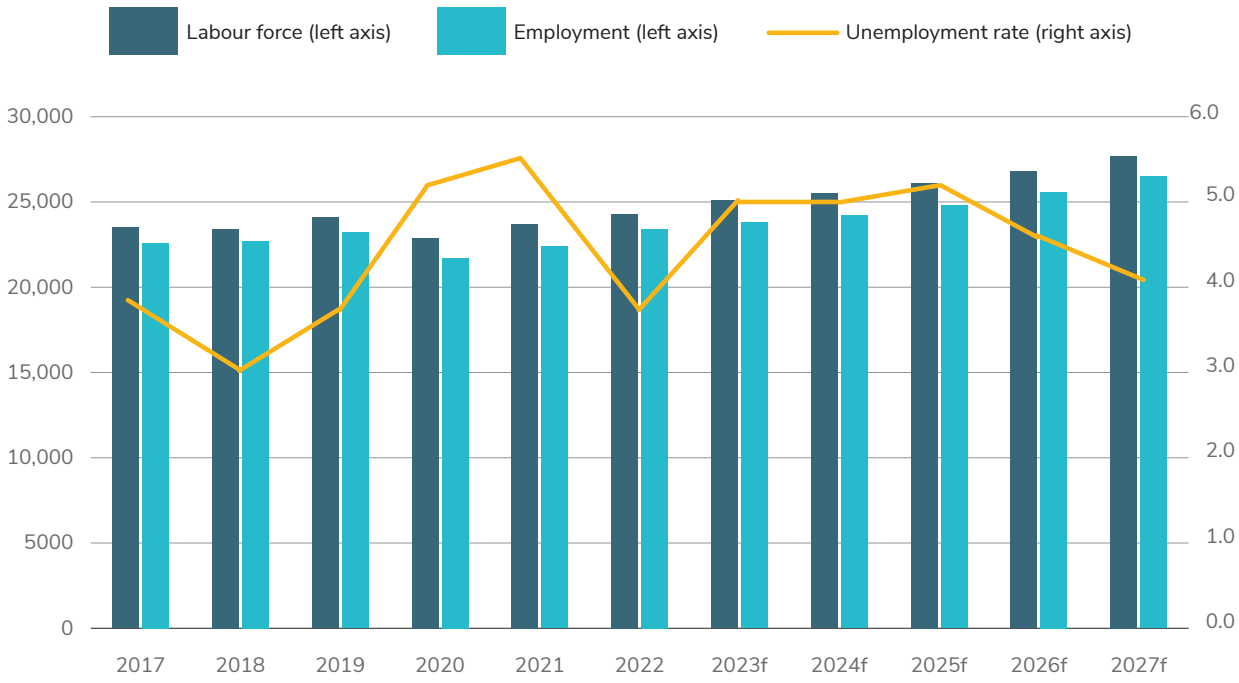
Production at Eagle Gold is expected to ramp up this year and operations at the Keno Hill mine are expected to resume in the third quarter. Higher mineral production and continued recovery of the tourism sector are expected to result in real GDP growth of 5.4 per cent in 2023 followed by 3.7 per cent growth in 2024. Further growth is projected throughout the remainder of the forecast, averaging 3.7 per cent growth through 2025 to 2027.

Further gains in the labour force and employment expected over the medium term

Strong demand for labour and increased economic activity spurred growth in the size of the labour force and employment as both reached record highs in 2022. Employment growth of 4.5 per cent last year outpaced the increase in the labour force and translated into a substantial decline in the territory's unemployment rate. At 3.7 per cent for the year, the Yukon's unemployment rate matched 2019's level and was the lowest in Canada.

Chart 4. Growth in employment and the labour force

Labour force (persons), employment (persons), unemployment rate (per cent)

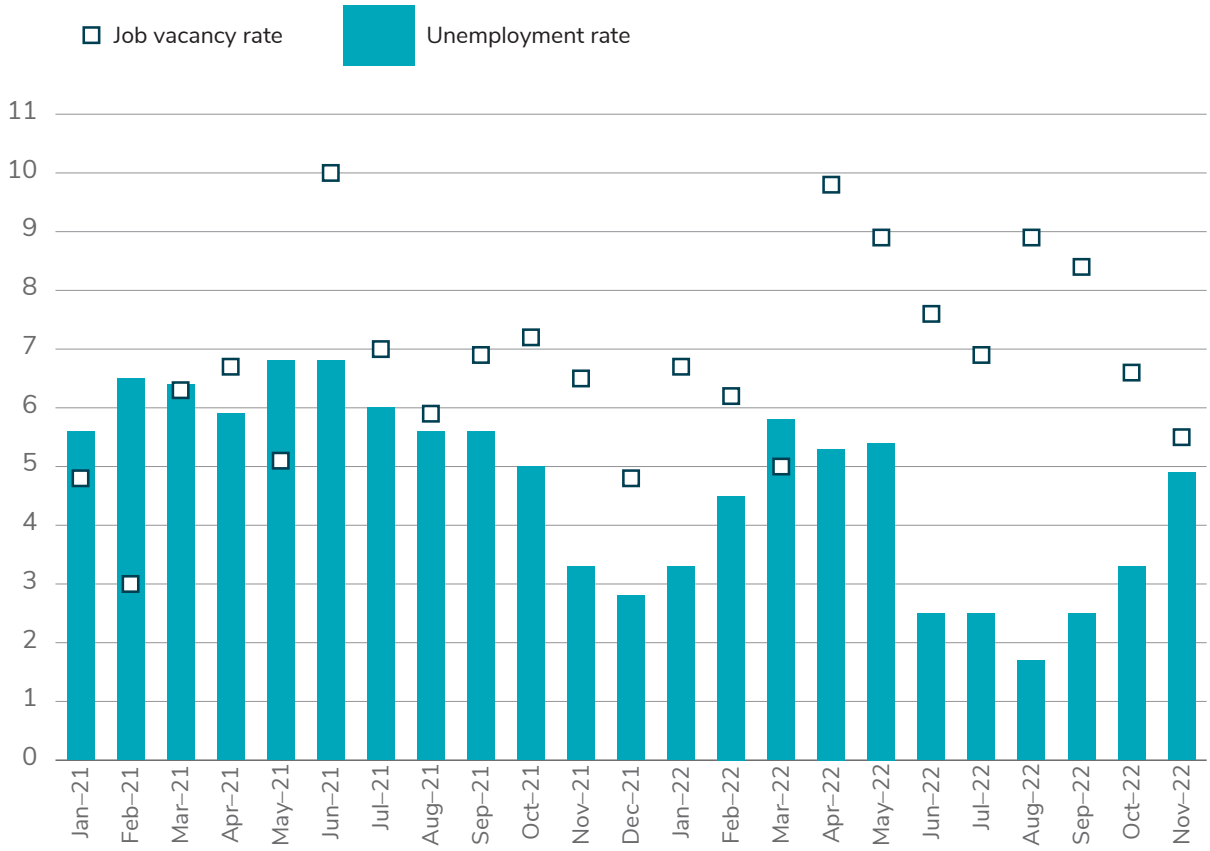


Source: Statistics Canada, Department of Finance *f = forecast*

Many employers in the Yukon and across the country have had difficulty finding workers. Job vacancies have been elevated in the territory throughout 2022, with the Yukon's job vacancy rate[11] among the top two highest rates in the country for all but one month. Like the experience of many jurisdictions in Canada, the job vacancy rate for the Yukon has recently been higher than the unemployment rate[12], further evidence of a tight labour market (Chart 5).

Chart 5. 2022 has seen tightness in the labour market return

Labour market indicators (per cent)



Source: Statistics Canada

11. The job vacancy rate is the number of job vacancies expressed as a percentage of labour demand, defined as all occupied and vacant jobs.

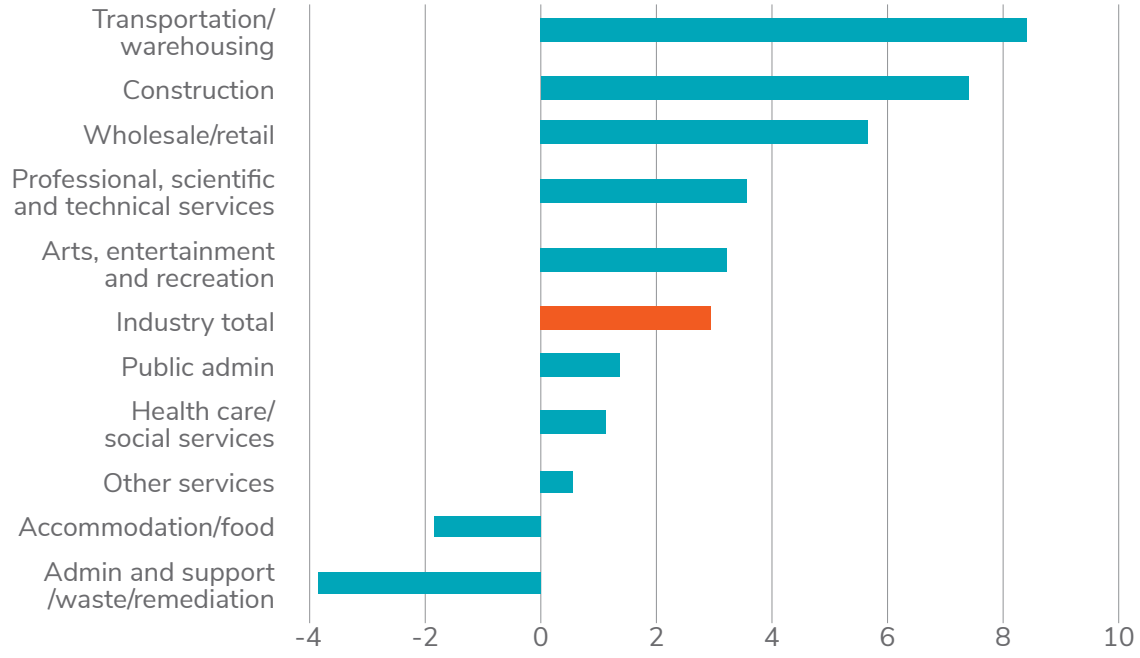
12. When the job vacancy rate exceeds the unemployment rate, this means there are proportionally more jobs seeking workers than workers seeking jobs.

Strong demand for workers at a time when supply is tight is placing upward pressure on wages and earnings. The average offered wage for vacant positions in the Yukon was the third highest in the country at $26.20 per hour in the third quarter of 2022[13], well above the national average of $24.20 per hour and up almost 10 per cent from 2021.

The recent increase in weekly earnings was not as pronounced as the increase in offered wages, but earnings are up across most industries (Chart 6). The average worker in the territory earned $1,334 per week through the first eleven months of 2022, up 2.9 per cent from the same period in 2021. Average weekly earnings for the Yukon ranked third in the country, behind only Nunavut and the Northwest Territories, and were well above the national average of $1,166 per week. While in some cases wages are not keeping pace with inflation, rising incomes have helped to mitigate the inflationary impacts being felt.

Chart 6. Wage pressures reflected in higher earnings across most industries

Average weekly earnings, seasonally adjusted, Jan–Nov 2022 change from Jan–Nov 2021 (per cent)



Source: Statistics Canada

Over the medium term, higher earnings are expected to draw more people into the labour force. The Yukon's labour force is projected to grow slightly faster than employment over the forecast period. This results in a higher projected unemployment rate in the neighbourhood of five per cent. While up from historic lows in recent years, the unemployment rate is projected to remain relatively low, and continue to be one of the lowest in Canada.

13. Average offered wage data is from Statistics Canada table 14-10-0325-01 and is available on a quarterly basis starting with the first quarter of 2015.

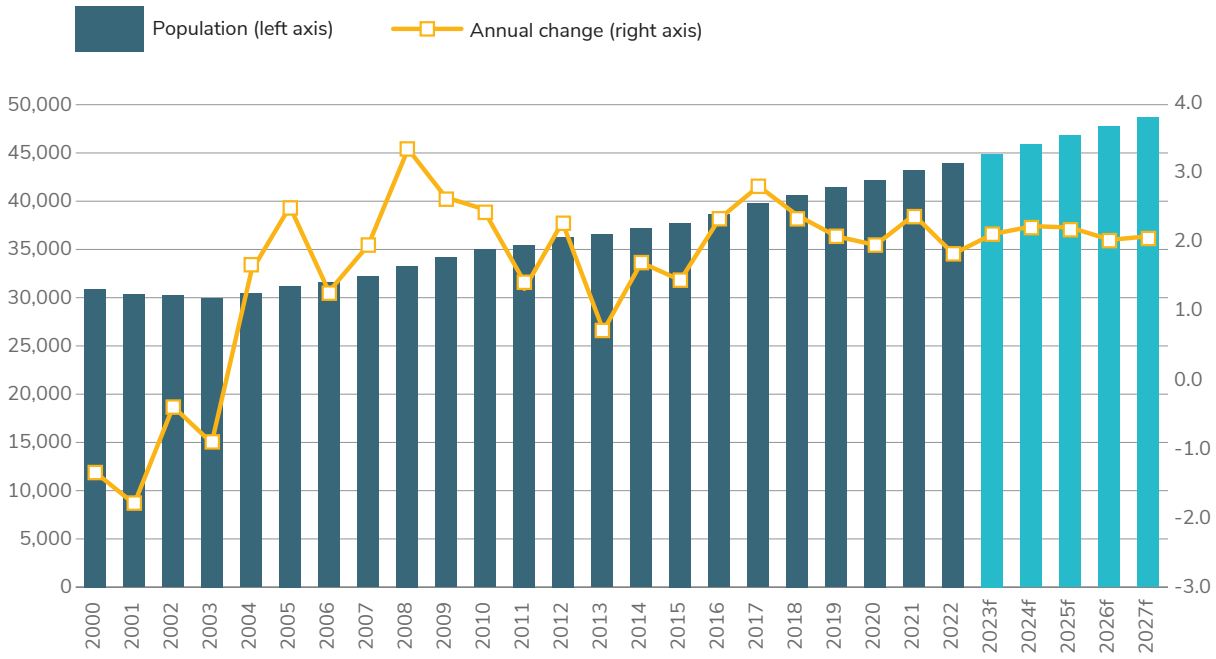
Further population gains anticipated in 2023

At 43,964 on June 30, 2022, the Yukon's population was up 1.8 per cent from 2021.[14] Growth in 2022 was driven primarily by net international migration of 550, which was the highest ever reported.[15] Over the last 20 years, the Yukon's population has grown just over 44 per cent. This growth was second only to Alberta (45.2 per cent) among all provinces and territories and was well ahead of the national growth of 24 per cent. A positive outlook for the territory's economy and labour market is expected to support strong migration into the Yukon and population growth over the medium term.

The federal government is targeting nearly 1.5 million new permanent residents over the 2023 to 2025 period.[16] High levels of immigration should increase the local supply of labour and help alleviate some of the tightness in the labour market. While helping on the labour front, more people moving to the territory has the potential to place further strain on the Yukon housing market, as supply has struggled to keep pace with demand in recent years.

Chart 7. Population is forecast to approach 49,000 by 2027

Population (persons), annual change (per cent)



Source: Yukon Bureau of Statistics *f = forecast*

14. June 30 estimates are considered annual estimates.

15. Statistics Canada's table 17-10-0005-01 reports data for population estimates by age and sex as of July 1.

16. *Government of Canada's Immigration Levels Plan for 2023–2025*. Immigration, Refugees and Citizenship Canada (November 1, 2022).

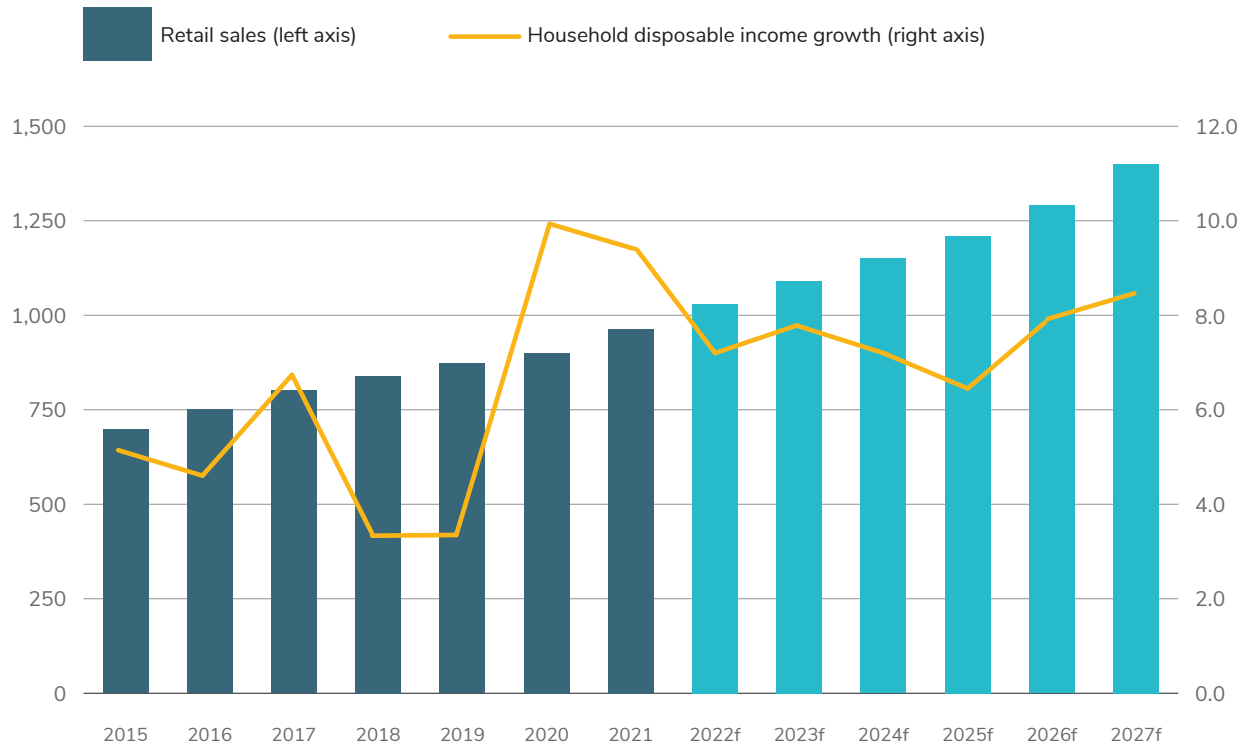
Countering some of the gains in international migration in 2022 was a net outflow of interprovincial migration resulting in 83 fewer residents. This was the first time net interprovincial migration was negative since 2013. Population is projected to increase in every year of the current forecast with growth averaging 2.1 per cent per year. By 2027, the last year of the forecast, the Yukon's population is expected to be near 49,000.

Retail sales exceeded $1 billion in 2022

Retail sales exceeded one billion dollars for the first time in 2022. Estimated growth of 6.8 per cent in 2022 is more than double the growth rate from the previous year. Prices were the primary driver of last year's growth in retail sales, with the estimated percentage increase in retail sales equivalent to the 6.8 per cent increase noted in the Whitehorse CPI. The current forecast has retail sales growing every year by an average of 6.3 per cent per year, significantly higher than the projected CPI increases over the same time span.

Chart 8. Income growth a key driver of retail sales growth

Retail sales ($ millions), Household disposable income growth (per cent)



Source: Statistics Canada, Department of Finance *f = forecast*

By 2027, the last year of the forecast, the Yukon's population is expected to be near 49,000.

Inflation has increased globally

Global supply chain disruptions and the war in Ukraine contributed to higher food and energy prices in 2022 and added to inflationary pressures noted all over the world. In Canada, domestic factors, including excess demand for labour and other inputs, have also fueled price growth, with the national inflation rate touching levels in 2022 not seen since the early 1980s.

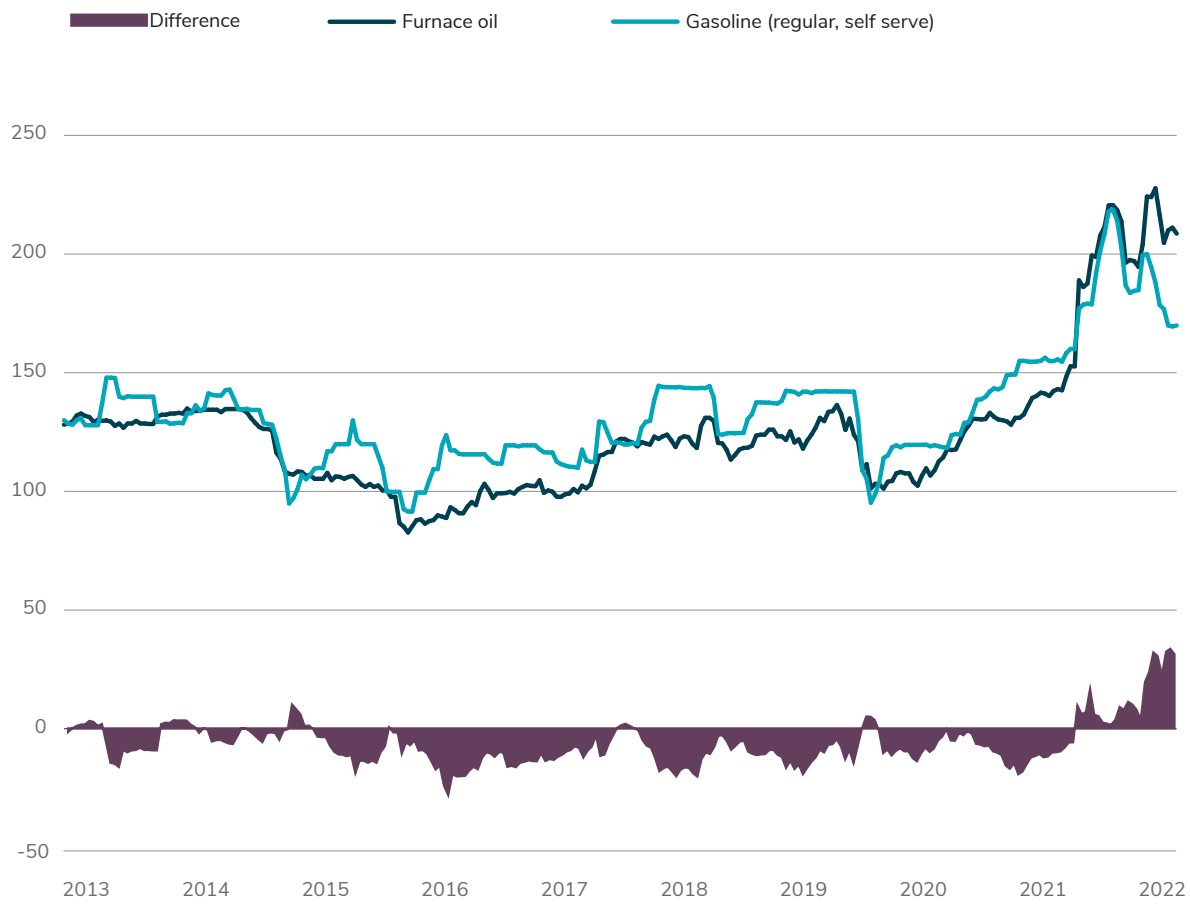
Rapid appreciation of prices for a large variety of consumer goods and services has also been the reality for Yukoners. The inflation rate in Whitehorse[17] averaged 6.8 per cent in 2022, the highest rate for the Whitehorse CPI since records began in 1982. Prices were up across most categories.

Higher fuel prices in 2022 were a prominent driver of overall inflation, with the price of gasoline up 29 per cent, and the price of fuel oil up 47 per cent compared to 2021. While gasoline prices have fallen by over 20 per cent from the peak in June, the price of fuel oil has remained elevated (Chart 9). This reflects global trends. US inventories of distillate fuels, including home heating oil and diesel, are at multi-year lows. Sanctions on Russia have led to Europe shifting towards non-Russian imports. While prices have stabilized, futures prices suggest that diesel and fuel oil prices are likely to remain at a hefty premium to gasoline in the near term.

17. Data are not available for the Yukon, only Whitehorse.

Chart 9. Gap between gasoline and other fuels has widened due to distillate shortage

Whitehorse fuel prices (cents per litre)



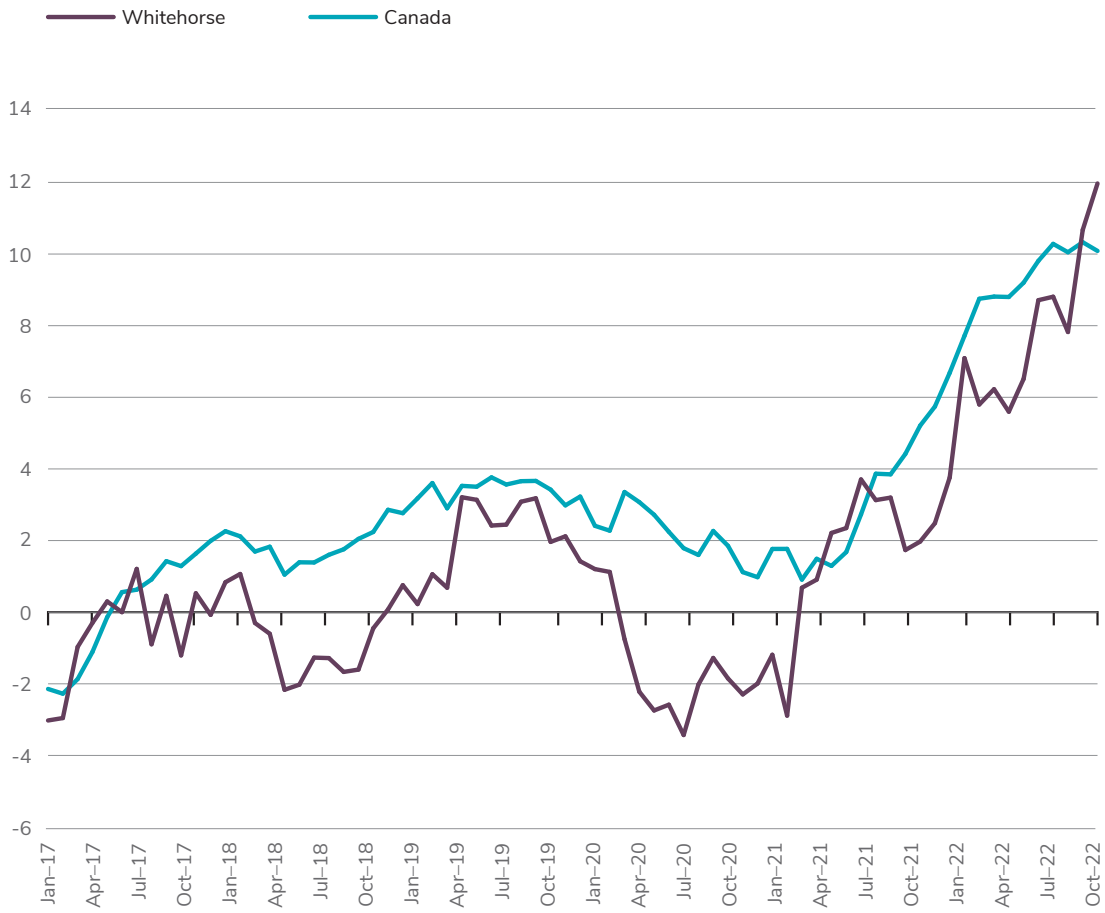
Source: Yukon Bureau of Statistics

Fuel oil is weighted heavier in the Whitehorse CPI than in the national index, because a substantially higher share of Yukoners use fuel oil for heat. This higher weighting is one of the reasons why inflation of 8.1 per cent in Whitehorse as of December was higher than the national rate of 6.3 per cent.

Another factor is that price pressures on food were slower to materialize in the Yukon than in the rest of Canada (Chart 10). Food prices in Canada rose throughout the pandemic, whereas in Whitehorse, they did not start to increase in earnest until later. Ultimately, prices in Whitehorse follow national trends closely and food prices have started to catch up. Inflation in Whitehorse was lower at the beginning of the year and higher at the end, averaging out over the course of the year with annual inflation for both Canada and Whitehorse coming in at 6.8 per cent.

Chart 10. Food price inflation was slower to materialize in Whitehorse

Year-over-year per cent change in the food component of CPI



Source: Statistics Canada

On January 25, 2023, the Bank of Canada increased its policy interest rate to 4.5 per cent to try to reduce the excess demand in the economy. The Bank signaled that it expects to "hold the policy rate at its current level while it assesses the impact of the cumulative interest rate increases."[18] The Bank has increased the policy rate by 4.25 percentage points since last March, the most in such a short span since the Bank began targeting interest rates in the early 1990s.

18. News release – *Bank of Canada increases policy interest rate by 25 basis points, continues quantitative tightening*. Bank of Canada. (January 25, 2023).

Most forecasters expect inflation in Canada will move towards historic norms over the next couple of years as supply chain problems subside and the effect of higher interest rates move through the economy. Canadian inflation is expected to decline from near 7 per cent in 2022, to between 3.5-4.0 per cent in 2023, and many forecasts are calling for inflation in 2024 to approach the midpoint of the Bank of Canada's target range of 1-3 per cent. Similarly, the average annual rate of inflation for Whitehorse is projected to fall from 6.8 per cent in 2022 to 3.8 per cent in 2023 and 2.5 per cent in 2024.

The housing market remains relatively strong but there are signs of cooling

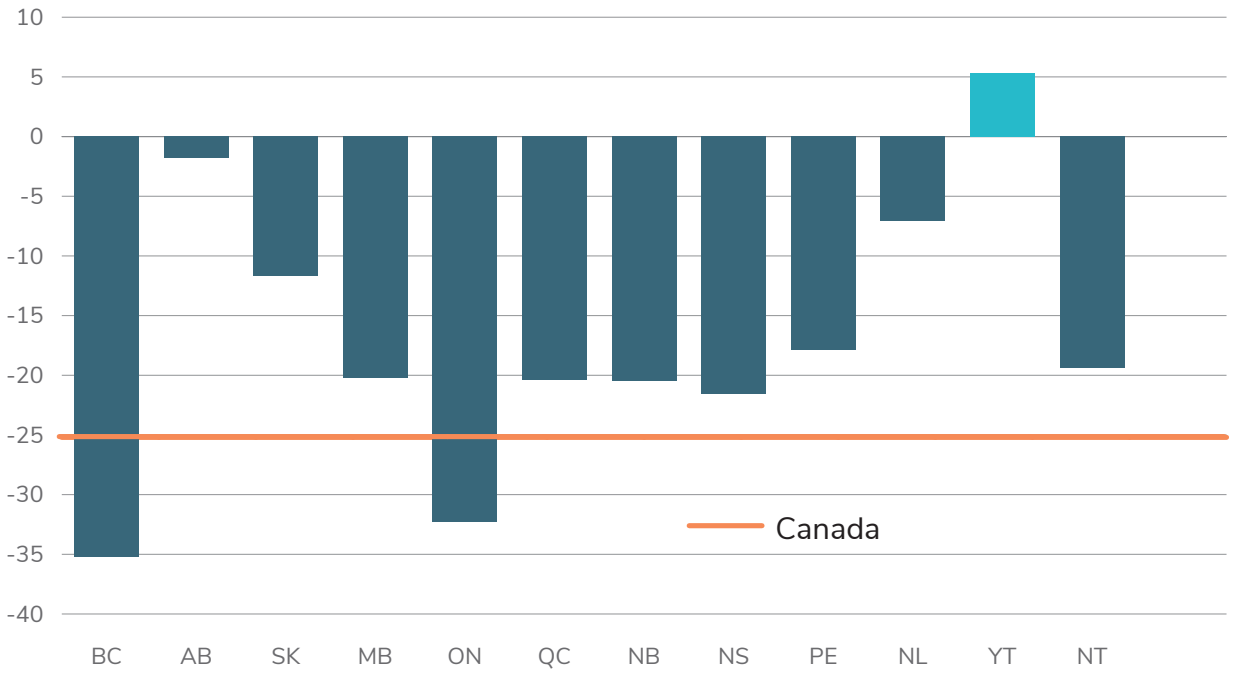
Locally, housing prices have been strong for several years, driven in part by high demand. A generally strong economy has drawn people to the territory. Housing supply has struggled to keep pace with demand, and this has been reflected in upward pressure on housing prices. Prices in Whitehorse across all housing types have seen notable growth in recent years. The average weighted price of single detached homes, duplexes and mobile homes all reached record highs in 2022. Condominium prices in 2022 were down slightly from the 2021 record high.

Even during an extended period of very low interest rates and growing household earnings, housing affordability has been eroding due to higher prices. More recently, rapid growth in interest rates has increased borrowing costs for new homebuyers and those on variable rate mortgages. Higher costs will filter through to fixed rate mortgages as they come up for renewal.

Higher interest rates took steam out of housing markets across the country. Average home prices in most Canadian markets fell over the second half of 2022. This effect was slower to materialize in the Yukon, which was the only jurisdiction that saw higher home sales in 2022 than in 2021 (Chart 11). It wasn't until the fourth quarter that signs of cooling showed in the Yukon data.[19] While increasing on average in 2022, average sales prices were down in the fourth quarter of last year across all housing types. Compared to the fourth quarter of 2021, prices were down by 1.2 per cent for single-detached, 3.9 per cent for duplexes, 11.4 per cent for condominiums and 1.6 per cent for mobile homes.

Chart 11. The Yukon experienced growth in the number of residential sales in 2022[20]

Residential sales, 2022 change from 2021 (per cent)



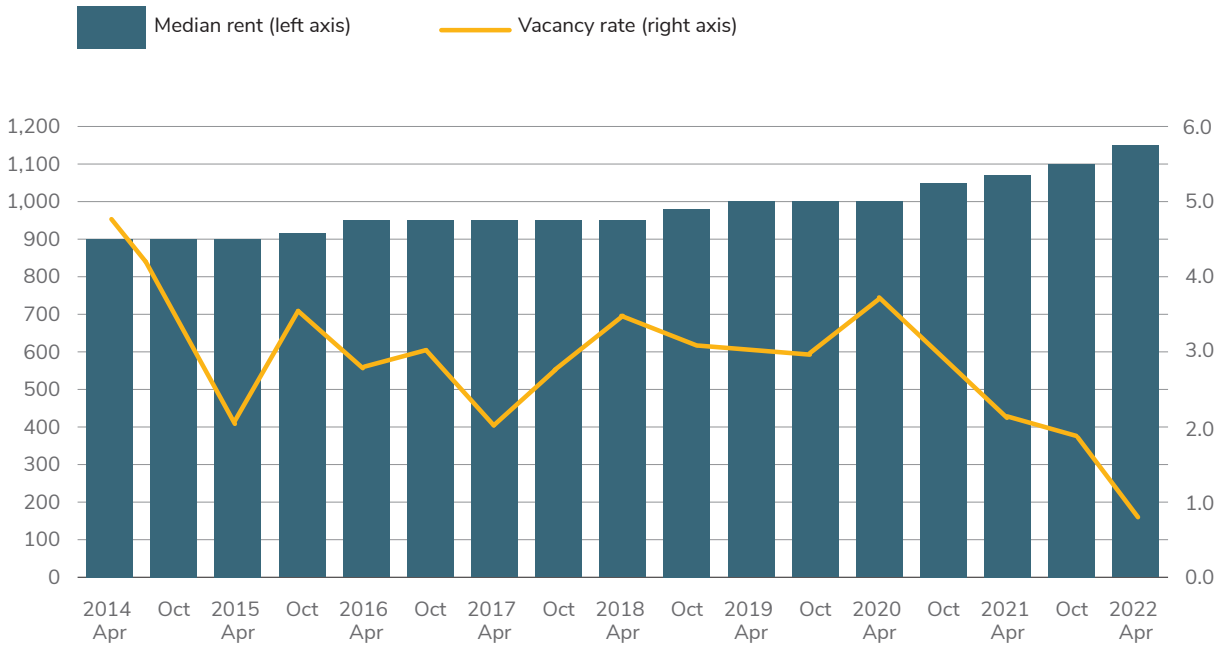
Source: The Canadian Real Estate Association

19. *Yukon Real Estate Report Fourth Quarter*, 2022. Yukon Bureau of Statistics. (February 2023).
20. The Canadian Real Estate Association does not publish data for Nunavut.

On the rental side, the market in recent years has been one of limited supply and increasing rents. The vacancy rate in buildings with three-or-more units fell to 0.8 per cent in April 2022, well below the 1.9 per cent reported in October 2021.[21] High demand and a lack of vacant units has translated into higher rents, with a median rent of $1,150 in April of last year, up 4.5 per cent from the October 2021 figure and 7.4 per cent higher than the April 2021 figure.

Chart 12. Recent history of rental market is one of few vacancies and increasing rents

Whitehorse median rent ($) and vacancy rate (per cent), units in buildings with 3+ rental units



Source: Yukon Bureau of Statistics

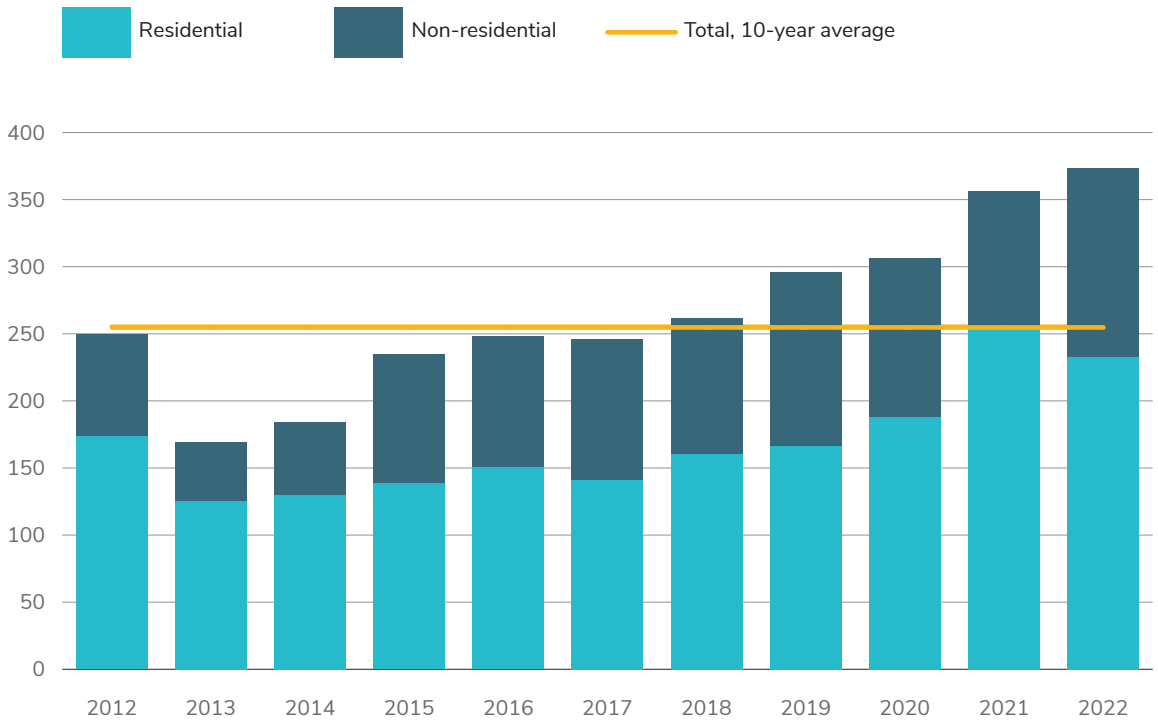
21. *Yukon Rent Survey April 2022*. Yukon Bureau of Statistics. (August 2022).

Residential investment remained strong in 2022

While below 2021's record level, investment in residential construction in 2022 continued to exceed investment on the non-residential side. Residential construction investment totalled $232.6 million in 2022, 62 per cent of the total $373.2 million in building construction reported for the period, and well above the ten-year average of $163 million for residential construction (Chart 13). The recent approval of phases 10 to 13 of the Whistle Bend subdivision will contribute to housing supply going forward.[22]

Chart 13. 2022 was another strong year for building construction

Investment in building construction ($ millions)



Source: Statistics Canada

22. *More phases of Whistle Bend subdivision approved* (January 19, 2023). Whitehorse Star.

Construction sector supported by commercial and government projects

The decline in residential spending from record highs was more than offset by increased non-residential spending. Investment in non-residential building construction totalled $140.6 million in 2022 and was up nearly 39 per cent from 2021 (Chart 13). Similarly, building permits for non-residential work were up substantially in 2022, growing 61 per cent to $150.7 million.

Government-related activities continue to be a primary driver of activity on the non-residential side. Growth was noted in both investment in building construction and building permits associated with institutional and governmental projects, up 83 per cent and 13 per cent, respectively. On the building permits side, construction of a new elementary school in Whitehorse's Whistle Bend subdivision and renovation of the Elijah Smith School were prominent contributors to last year's gains. Commercial permits also showed strong growth in 2022, more than doubling from $44.1 million to $97.0 million. Permit value was supported by construction of a three-storey office building in Whitehorse, renovation of the Old Territorial Administration building in Dawson City and work related to the Whitehorse Battery Energy Storage project.

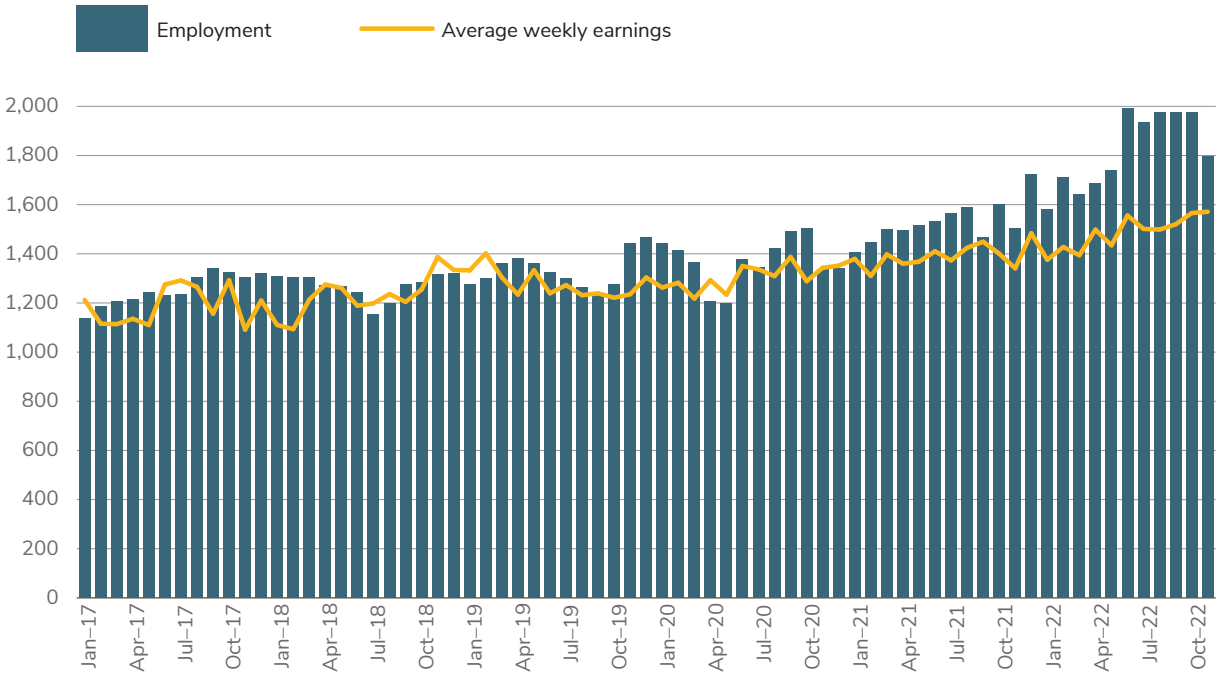
Higher input and labour costs continue to factor into some of the recent gains in building construction investment, due in part to supply chain constraints and stiff competition for tradespeople. Nationally, residential construction costs, on average, were 19 per cent higher and non-residential costs 13 per cent higher in 2022 compared to 2021.[23]

Increased activity created jobs in the construction sector and boosted wages. Construction employment reached an all-time high of 1,993 in June 2022 (Chart 14), up more than 50 per cent versus June 2019. Through the first eleven months of 2022, construction workers earned $1,486 per week on average, an increase of 7.4 per cent from 2021.

23. National figures are based on a composite of 11 census metropolitan areas.

Chart 14. Busy construction sector reflected in growth in construction employment and earnings

Employment (persons), Average weekly earnings ($)



Source: Statistics Canada

The Government of Yukon's *Five-Year Capital Plan* outlines spending to the end of fiscal year 2027–28 of $2.15 billion and includes significant spending in several priority areas such as 'transportation infrastructure', 'land development, housing, education and health' and 'community and First Nations infrastructure'. Projects such as the Nisutlin Bay Bridge, the Dempster Fibre project and the new elementary school in Whistle Bend are examples of investment in critical infrastructure included in the latest Capital Plan. In addition to Government of Yukon projects, the City of Whitehorse also factors into expectations of construction activity with over $130 million in planned spending on capital projects over 2023 to 2026.[24]

24. Spending figure is from the City of Whitehorse's *Capital Expenditure Program 2023–2026* released on November 14, 2022. Figure includes all approved spending, including spending of approximately $75 million that is subject to external funding approval.

Mineral production forecast to be strong over the medium term

The Yukon's mining industry has remained resilient in the face of major headwinds in 2022. High winter precipitation resulted in a heavy spring thaw that hindered mineral production, as both the Eagle Gold and Minto mines lost a month of operations and the sluicing season for placer miners was delayed. The sector has been facing a shortage of workers coming out of the pandemic, hampering some operations. High fuel prices and supply chain issues also presented challenges in 2022.

In addition to disruptions during the spring thaw, operation at Eagle Gold was stalled for three weeks in the third quarter due to the failure of the belt on the overland conveyor. These operational issues caused gold production to fall to 150,182 ounces in 2022, below the previous year's production of 164,222 ounces. With production from Keno Hill underperforming expectations, Alexco Resource Corporation halted operations in June 2022 to focus on mine development. Operations remained suspended following the acquisition of Alexco by Hecla Mining Company in September.

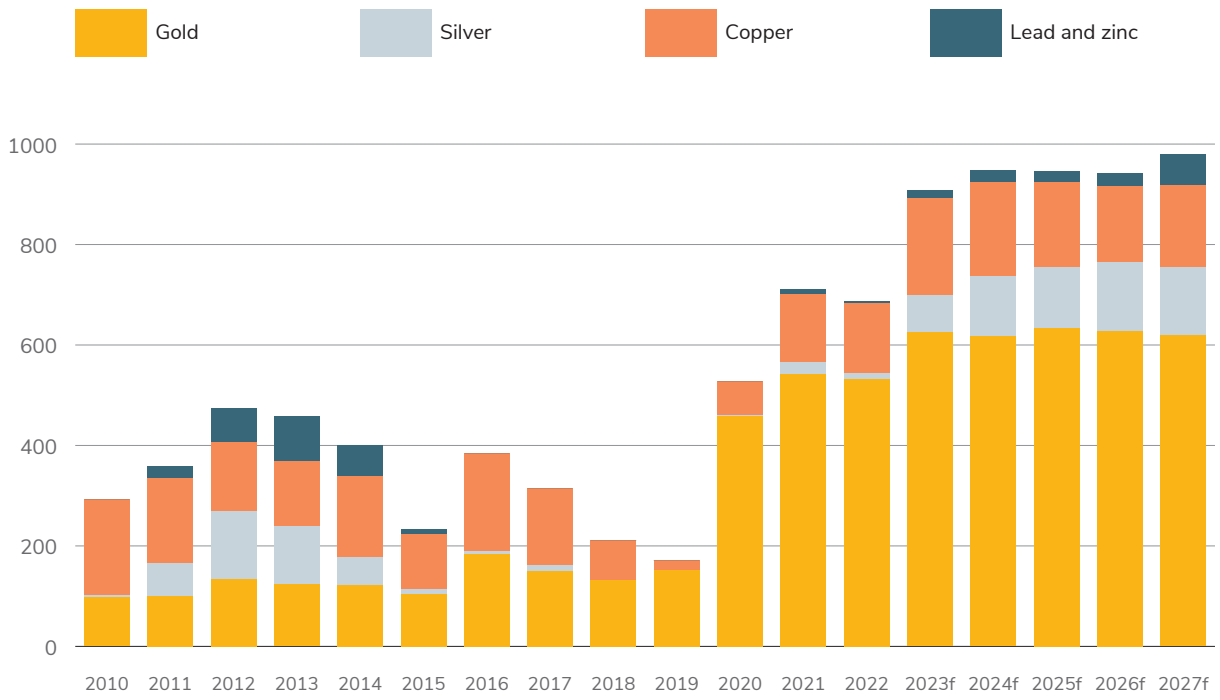
Production for the fourth quarter for the Minto mine was unavailable at the time of writing, but public statements from the President of Minto Metals Corporation in November 2022 noted that the expectation was that annual production would fall within their 2022 production guidance of 28-31 million pounds of copper.[25]

Placer miners also saw higher production. Placer gold production, according to export tax reporting, was 82,420 crude ounces (65,936 fine ounces), up from production of 80,484 crude ounces (64,387 fine ounces) in the previous year. At $154 million, the value of placer gold production accounted for about 22 per cent of 2022's total estimated mineral production.

25. News release – *Minto Metals announces 2022 third quarter results, revenue increased by 17% over the same quarter in previous year*. Minto Metals Corporation (November 17, 2022).

Chart 15. Mineral production value forecast to approach $1 billion[26]

Value of metal production in the Yukon ($ millions)



Source: Natural Resources Canada, Department of Energy, Mines and Resources, Department of Finance *f = forecast*

The Yukon's quartz miners expect to recover from the various setbacks that hindered 2022 production. Victoria Gold expects production at Eagle Gold to rebound in 2023 with production well above 2022's output as the project operator continues to work towards its annual target of 250,000 ounces. Hecla Mining Company announced earlier this year that mine development is ahead of schedule and that they plan to resume operations at Keno Hill in the third quarter of 2023. This, along with anticipated higher production at the Minto mine and sustained placer production, is expected to lead mineral production to rebound to $910 million in 2023 and exceed $900 million in all subsequent years of the forecast (Chart 15).

26. Due to data suppression of Statistic Canada's estimates, data presented for 2019, 2020 and 2021 are based on internal estimates.

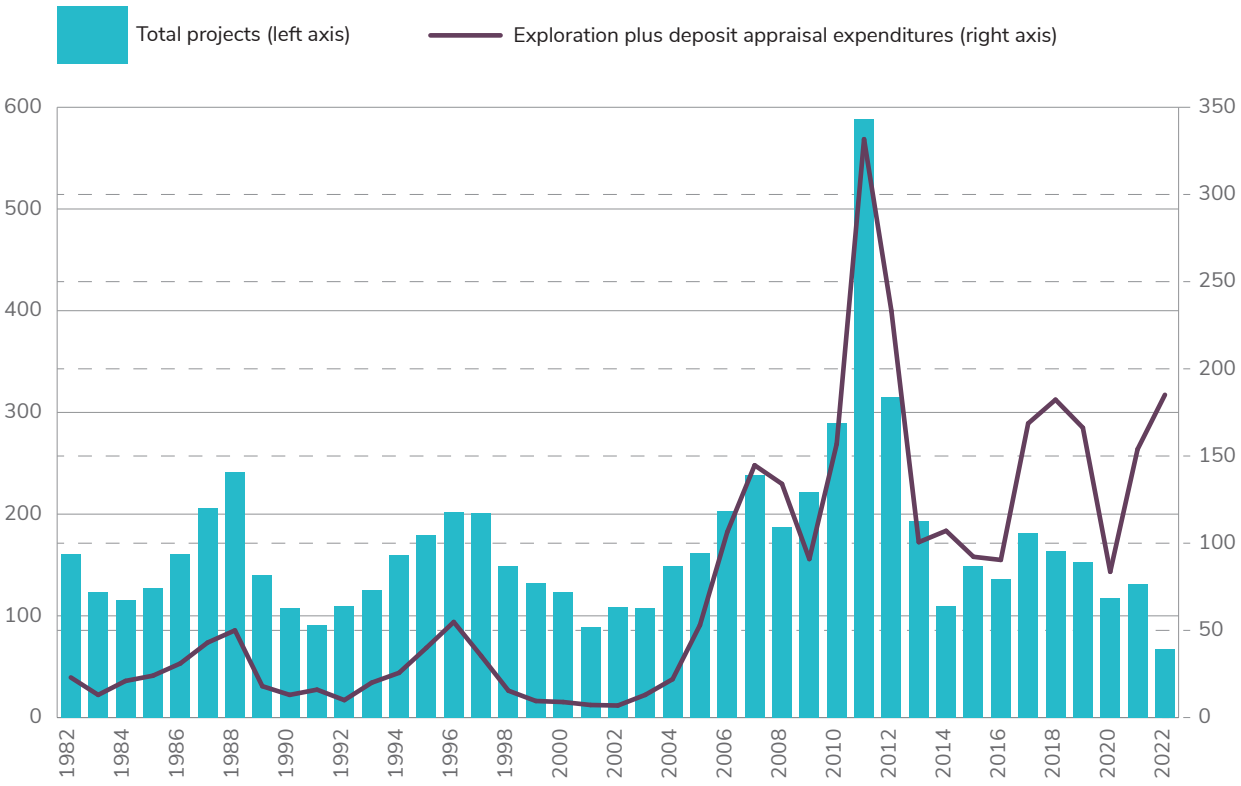
Mineral prices remain supportive of future development

Metals prices rallied to close out 2022 and, though down from earlier highs, remain well above pre-pandemic levels. This could spur development over the medium term for projects such as BMC Minerals Limited's Kudz Ze Kayah mine, Newmont Corporation's Coffee Gold project and Sabre Gold Mine Corporation's Brewery Creek project. Over the longer term, the advancing of the Casino project, a major global copper resource, may attract interest due to the pivotal role copper will play in the green economy and global electrification.

Higher metal prices offer investors the potential of better returns from the discovery of new deposits and exploration activities on current mining plays. Exploration spending has rebounded from pandemic lows. Revised spending intentions from Natural Resources Canada noted exploration spending in 2022 of about $185 million, up 20 per cent from $154 million in 2021 (Chart 16).

Chart 16. Number of active exploration projects trending down even as overall exploration spending has rebounded

Number of active projects, Exploration expenditures ($ millions)



Source: Department of Energy, Mines and Resources, Natural Resources Canada

Recent spending has been increasingly concentrated in a smaller set of mature projects, rather than early-stage projects. The number of exploration projects has fallen over the last several years to a 40-year low in 2022, despite overall spending rebounding.

Spending on exploration for precious metals accounted for 70 per cent of exploration spending in 2022, with the remainder on exploration for base metals. Precious metals are expected to continue to draw most of the interest in exploration activity over the forecast. This mix may eventually be impacted by Canada's critical minerals strategy (see Box 1), which seeks to increase the output of minerals deemed critical to the transition to green energy.

Box 1: Critical minerals a potential opportunity for the local mining industry and for the Yukon's energy goals

The release of *The Canadian Critical Minerals Strategy* in December 2022, along with an almost $4 billion commitment in Budget 2022, is a clear signal of the interest the federal government has in developing the country's critical minerals.

Ultimately, minerals noted as 'critical' reflect societal needs and values at a point in time. Canada's critical minerals strategy notes critical minerals as the building blocks of the green and digital economies, highlighting that "there is no energy transition without critical minerals: no batteries, no electric cars, no wind turbines and no solar panels."

Most of the 31 minerals that the Canadian government has published as being "critical" to Canada have known deposits or documented occurrences in the Yukon. While the territory's current production of critical minerals is quite modest, limited to copper production from the Minto mine and recent production of zinc and indium as a by-product at the Keno Hill mine, there is potential for production from existing identified deposits. Critical minerals are identified as prominent outputs of several potential mines including, Kudz Ze Kayah (zinc, copper); Casino (copper, molybdenum); Nickel Shäw (nickel, cobalt, platinum, palladium, copper) and Mactung (tungsten).

Given commitments by Canada and the Yukon to reduce carbon emissions, as well as the need to ensure future energy security, there is clear motivation to develop a reliable supply of critical minerals. With climate change and economic opportunity acting as strong motivators for development, critical minerals have the potential to be a prominent contributor to the local mining industry and the broader economy over the coming years.

Signs of a solid rebound in tourism activity, but a return to pre-pandemic levels will take time

The tourism sector has proven to be resilient in the face of what was an historic disruption to global travel.

Several key tourism metrics for the territory show significant improvement from the worst of the pandemic. The number of international border crossings into the Yukon totalled just over 168,000 in the first eleven months of 2022, almost five and a half times the number of crossings in the same period of 2021, and well above the 63,657 crossings reported for all of 2020 and 2021 combined when COVID-19 related travel restrictions weighed on visitation.

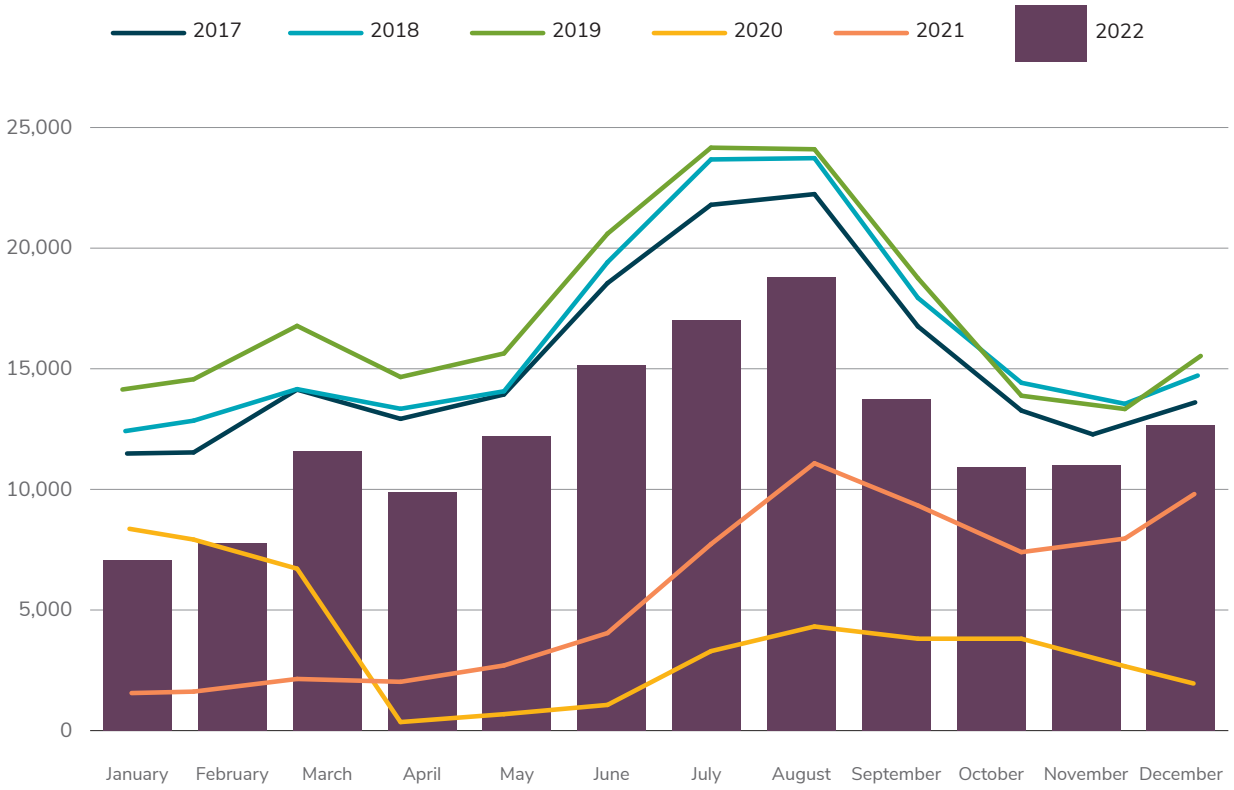
The tourism sector has proven to be resilient in the face of what was an historic disruption to global travel.

Like international border crossings, other indicators of performance are much improved from recent lows but continue to underperform pre-pandemic levels. Data for the first nine months of 2022 show international overnight visitation to be more than double the same period of 2021, but nearly 30 per cent lower than the five-year average.[27] Increased visitation is also reflected in increased hotel occupancy in 2022,[28,29] with data published by CBRE Hotels showing much higher occupancy rates in every month from January to November with the average of 56 per cent over this period, well ahead of the 41 per cent reported for the same period of 2021.[30]

An increased number of air arrivals in 2022 are another sign of the return of travel. Arrivals at Erik Nielsen Whitehorse International Airport were 2.2 times the number of arrivals from 2021 (Chart 17).

Chart 17. Air arrivals much improved from the last two years

Arrivals (deplaning passengers, thousands) at Erik Nielsen Whitehorse International Airport



Source: Statistics Canada

27. *Yukon Tourism Visitation Report, January to September 2022*. Department of Tourism and Culture. (December 22, 2022).
28. Occupancy rate is the percentage of occupied rooms expressed as percentage of the total available rooms at a given time.
29. Figures for the occupancy rate do not capture all hotel rooms in the Yukon, with about 600 rooms captured in this calculation.
30. Data taken from various CBRE Hotels monthly reports: *Trends in the Canadian Hotel Industry – National Market Report*.

Even with strong growth in 2022, air arrivals came in at only 72 per cent of arrivals in 2019, suggesting that there is still more room for recovery from the COVID-19 pandemic.

Tourism activity is increasing, but a variety of headwinds are slowing the recovery. Inflation is running at, or near, many decade highs, and is expected to remain elevated throughout much of 2023. Higher fuel costs have eaten into the bottom-lines of some service providers, particularly those that are fuel intensive such as providers of charter flights and tours.[31] Local tourism-service providers also continue to struggle with finding staff. Labour shortages in the accommodation and food services sector are more severe in the Yukon than they are in the rest of the country. Demand could also be impacted as higher interest rates lead to less discretionary spending.

Further improvement in key tourism metrics is expected. The Conference Board of Canada's latest Travel Markets Outlook supports this improving outlook for tourism, noting an expectation that visitation to the territory will reach pre-pandemic levels by 2024 or 2025, and that overnight visits will recover by 2024.[32] In addition, positive news, like White Pass Railroad's resumption of service to Canada in the summer of 2023, provides further evidence of a return to normalcy for the tourism sector.[33]

31. *Travel Exclusive Winter 2022/23 Travel Intentions Survey*. Canadian Tourism Research Institute. The Conference Board of Canada (December 2022).

32. *Emerging from the Wilderness – Yukon's Travel Markets* Outlook to 2026. The Conference Board of Canada. (January 24, 2023).

33. *White Pass Railroad to resume service to Canada this summer* (January 13, 2023). KHNS FM.

Appendix:
Key economic indicators

	2021	2022	2023f	2024f	2025f	2026f	2027f
Gross Domestic Product (GDP)							
Real GDP by Industry (2012$ millions)	3,045	3,138 (f)	3,308	3,431	3,534	3,666	3,831
Per cent change	10.0	3.1	5.4	3.7	3.0	3.7	4.5
Nominal GDP ($ millions)	3,704	4,049 (f)	4,432	4,795	5,093	5,480	5,948
Per cent change	14.3	9.3	9.4	8.2	6.2	7.6	8.5
Mineral Production *							
Metal production ($ millions)	710	690 (f)	910	950	950	940	980
Labour market							
Labour force *	23,700	24,300	25,100	25,500	26,100	26,800	27,700
Employment *	22,400	23,400	23,800	24,200	24,800	25,600	26,500
Unemployment rate	5.5	3.7	5.0	5.0	5.1	4.5	4.1
Participation rate	72.3	72.8	73.0	72.4	72.1	72.2	72.6
Income							
Household income ($ millions)	2,440	2,664	2,849	3,029	3,210	3,463	3,760
Per cent change	11.4	9.2	6.9	6.3	6.0	7.9	8.6
Consumers							
Consumer price inflation^	3.3	6.8	3.8	2.5	2.0	2.0	2.0
Retail sales ($ millions) *	963	1,030 (f)	1,090	1,150	1,210	1,290	1,400
Population							
Population*	43,190	43,964	44,900	45,900	46,800	47,700	48,700
Per cent change	2.3	1.8	2.1	2.2	2.1	1.9	2.0
Key Assumptions							
Gold (USD/t oz)	1,800	1,809	1,760	1,670	1,650	1,650	1,650
Silver (USD/t oz)	25.15	22.16	21.85	21.68	22.00	22.00	22.00
Copper (USD/lb.)	4.23	3.99	3.48	3.71	3.55	3.55	3.55
Zinc (USD/lb.)	1.36	1.58	1.33	1.25	1.23	1.15	1.15
Lead (USD/lb.)	1.00	0.97	0.91	0.91	0.93	0.93	0.93
Can/US exchange rate	0.80	0.77	0.75	0.77	0.78	0.78	0.78

f = forecast

^ = CPI available only for Whitehorse, annual average.

** = Forecasts are rounded. Annual per cent change based on unrounded figures.*

Source: Statistics Canada, Bank of Canada, Yukon Bureau of Statistics.

Population projections are produced by Yukon Bureau of Statistics. Metal prices forecasts are informed by prominent forecasters. All other forecasts are produced by the Department of Finance's Economic Research branch based on data available as of February 13, 2023.

Yukon

THE YUKON ELECTRICAL COMPANY LIMITED
An ATCO Company

YUKON ENERGY

YUKON ENERGY CORPORATION

AND

THE YUKON ELECTRICAL COMPANY LIMITED

TERMS AND CONDITIONS

OF

SERVICE

Effective: 2011-07-01
Supercedes: 2005-10-06

Board Decision: 2011-05

THE YUKON ELECTRICAL COMPANY LIMITED
An ATCO Company

YUKON ENERGY

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THE YUKON ELECTRICAL COMPANY LIMITED
An ATCO Company

YUKON ENERGY

1. INTRODUCTION

The Yukon Electrical Company Limited (Yukon Electrical) and Yukon Energy Corporation (Yukon Energy) each provide direct electrical Service to Yukon Territory Customers under a common Electric Service Tariff. The Electric Service Tariff is comprised of the Rate Schedules and these Terms and Conditions of Service (the "Terms and Conditions", formerly known as the "Electric Service Regulations"). Yukon Electrical and Yukon Energy conduct their business activities in compliance with these Terms and Conditions.

These Terms and Conditions are regulated by the Yukon Utilities Board (hereinafter referred to as the "Board"), in accordance with the Yukon *Public Utilities Act*, and may not be changed without the approval of the Board. Parties having any inquiries or complaints regarding these Terms and Conditions may direct such inquiries or complaints directly to Yukon Electrical, Yukon Energy or the Board.

The Electric Service Tariff is available for public inspection during normal business hours at the business offices of Yukon Electrical and Yukon Energy and at the offices of the Board and can be accessed on the Companies' respective websites at: www.yukonelectrical.com and www.yukonenergy.ca .

2. INTERPRETATION

2.1 Definitions

The following words or phrases, when used in these Terms and Conditions, the Electric Service Tariff or an application, contract or agreement for service, shall have the meaning set forth below.

"Billing Demand" - the demand upon which billing to a Customer is based as specified in a rate schedule or contract

"Board" - the Yukon Utilities Board.

“Capital Cost” the cost of materials, labour, equipment, expenses and any other direct or indirect costs incurred by the Company in extending Service to a Point of Service.

"Company" - The Yukon Electrical Company Limited or Yukon Energy Corporation.

"Connected Load" - the sum of the capacities or ratings of the electric Energy consuming apparatus connected to a supplying system.

“Connection Fee” – a non-refundable fee charged when a new Service is connected or an existing Service is reconnected or a meter reading is required to add the Customer to the Company’s system. (refer to Schedule D for fees).

"Construction Contribution" – a specific payment by a Customer to offset Company costs incurred in extending Service that will primarily benefit that or group of Customers only and not the other ratepayers in the distribution system. The contribution will be the difference between the cost of extending the Company’s Facilities to serve a Customer or group of Customers and the Maximum Available Company Investment specified in Schedule B.

“Cost Sharing” – the process whereby a new Customer or group of Customers who connect to an existing Facility for which another Customer or group of Customers has paid a Construction Contribution, is assessed their share of that Construction Contribution which must be paid to the Company to be refunded to the existing Customer(s).

“Current Limiting Device” – a device that limits the amount of Demand available to a specific Customer.

"Customer" - a person, firm, partnership, corporation, association or organization (including, without limitation, individual members of any unincorporated entity) to who the Company provides any Service hereunder including all owners and occupants of a premises, whom normally reside at the premises during the time for which Service was provided to that premises whether or not such owner or occupant's name appears on the application for Service.

"Demand" - the maximum rate at which electric Energy is delivered by the Company (expressed in kilowatts, kilovolt amperes or other suitable unit) at a given instant or averaged over any designated period of time.

"Electric Service Regulations" – the former title of this document outlining the terms and conditions governing Service, which title has been replaced by Terms and Conditions of Service. Where reference is made to Electric Service Regulations it shall be deemed to be a reference to these Terms and Conditions of Service as amended from time to time.

"Energy" - electric energy consumed expressed in kilowatt hours.

"Estimated Capital Cost" – the estimated cost of materials, labour, equipment, expenses, and any other direct or indirect costs for extending Service to a Point of Service.

"Facilities" - a physical plant including, without limitation, generating plants, transmission and distribution lines, transformers, meters, equipment and machinery.

"Force Majeure" - circumstances not reasonably within the control of the Company, including acts of God, strikes, lockouts or other industrial disturbances, acts of the public enemy, wars, blockades, insurrections, riots, pandemics, epidemics, landslides, lightning, earthquakes, fires, storms, floods, high water, washouts, inclement weather, orders or acts of civil or military authorities, civil disturbances, explosions, breakdown or accident to equipment, mechanical breakdowns, the intervention of federal, territorial, or local government or from any of their agencies or boards (excluding Decisions and/or Orders made by the Board in the normal course of it exercising its authority to establish the revenue requirement of the parties to this agreement), the order or direction of any court and any other cause, whether of the kind herein enumerated or otherwise.

"In-Service Date" - the date on which the Customer specifies Service is to be available or the date the Service is actually available, whichever is later.

"Interconnected System" - those portions of the Company's Facilities which are connected to the Whitehorse/Aishihik/Faro (WAF) power grid or to the Mayo-Dawson grid.

"Isolated System" - those portions of the Company's Facilities which do not form part of the Interconnected System.

"Load" - the Demand and Energy delivered to or required at any Point of Service.

"Load Factor" - the ratio of the average Demand (in kilowatts) supplied during a designated period to the peak or maximum Demand(in kilowatts) occurring in the period expressed as a percentage derived by:

(a) multiplying the Energy used in the designated period by 100;
(b) multiplying the maximum Demand by the number of hours in the designated period; and
(c) dividing (a) by (b).

"Maximum Company Investment" – the maximum Capital Cost which the Company will incur to extend Service to a Point of Service as set forth in Schedule B hereto.

"Multiple Dwelling" - a residential building containing more than one Single Family Dwelling unit.

"Point of Service" - the point at which the Company's service conductors are connected to the wires or apparatus of a Customer.

"Power Factor" - the ratio of the highest metered kilowatt Demand in a billing period to the highest metered kilovolt ampere Demand in that same billing period.

"Satisfactory Credit Rating" – determined subject to the discretion of the Company, and may include the Customer having paid all bills on an existing Company account in full on or before the due date of the said bill for 12 consecutive months or a similar payment record as established with another utility service provider within the past twelve months.

"Security Deposit" – the amount determined in accordance with Article 4.6.

"Service" - the delivery of Energy by the Company at the Demand required by the Customer.

"Service Connection" the Facilities required to physically connect the Customer's facilities to the Company's system.

"Single Family Dwelling" - a private residence which is not a Multiple Dwelling, consisting of single family living quarters having, in one self-contained unit, at least sleeping quarters, and, a kitchen.

2.2 Conflicts

If there is any conflict between a provision expressly set out in an Order of the Board and these Terms and Conditions, the Order of the Board shall govern.

2.3 Headings

The division of these Terms and Conditions into sections, subsections and other subdivisions and the insertion of headings are for convenience of reference only and shall not affect the construction or interpretation of these Terms and Conditions.

2.4 Schedules and Appendices

The following schedules and appendices are attached to and form part of these Terms and Conditions:

- Schedule A - Standard Supply Specifications
- Schedule B - Maximum Company Investment
- Schedule C - Conditions for Underground Subdivisions
- Schedule D - Fees and Service Charge Summary

3. GENERAL PROVISIONS

3.1 Board Approval

These Terms and Conditions have been approved by the Board. The Company may amend these Terms and Conditions by filing a notice of amendment with the Board and interested parties from the preceding General Rate Application. Included in the notice shall be notification of which Customer groups are affected by the amendment and an explanation of how affected Customers will be notified of the amendments. If the Board approves the notice of the amendment, the amendment will take effect upon the date set by the Board. If no specific date is set by the Board then the amendment will take effect on the date of the Board's Order approving the notice of amendment.

3.2 Terms and Conditions Prevail

(a) These Terms and Conditions, as amended from time to time, apply to the Company and to every Customer to which the Company provides a Service Connection.

(b) The application for a Service Connection (whether verbal or written), the use by the Customer of a Service Connection to obtain Electricity Services or the payment by the Customer of an account rendered by the Company in relation to a Service Connection shall constitute acceptance by the Customer of these Terms and Conditions.

(c) No agreement can provide for the waiver or alteration of any part of these Terms and Conditions unless such agreement is first filed with and approved by the Board.

3.3 Ownership of Facilities

Unless otherwise specifically provided in a contract with the Customer, notwithstanding the payment by a Customer of any costs incurred by the Company, the Company shall install, maintain and retain full title and ownership of all lines, equipment and other Facilities on its side of the Point of Service and of all meters and metering equipment provided and/or installed by it.

3.4 Use of Energy

Service is provided only for the purposes specified by contract or by the rate schedule applicable to such Service. A Customer shall not sell Energy provided by the Company unless otherwise provided by a contract with the Company, or unless the Company has first given written consent.

3.5 Customer Extensions

A Customer shall not extend service Facilities beyond property owned or occupied by the Customer.

3.6 Customer Generation

A Customer must notify the Company and sign an agreement with the Company if the Customer wishes to have service;

a) in parallel operation with; or
b) as supplementary, auxiliary or stand-by Service to any other source of electric Energy.

3.7 Frequency and Voltage Levels

The Company will make every reasonable effort to supply energy at 60-Hertz alternating current. The voltage levels and variations will comply with the Canadian Standards Association standards and shall be in accordance with the Company's standard supply specifications as set out in Schedule A except in locations where the voltage levels set out in Schedule A are not available.

3.8 Fees and Other Charges

The Company will provide all standard services hereunder pursuant to the approved Electric Service Tariff. All additional and supplementary services provided by the Company to a Customer will be charged a separate rate or fee, such as those included, without limitation, in Schedule D herein. Payment for these services shall be in accordance with the provisions of these Terms and Conditions.

4. APPLICATION FOR AND CONDITIONS OF SERVICE

4.1 General Requirements

(a) Any applicant for Service may be required to sign an application or a contract for Service, and shall supply information respecting Load, preferred supply conditions and the manner in which Energy will be utilized. An applicant may also be required to establish a Satisfactory Credit Rating with the Company and/or provide a Security Deposit prior to being connected for Service.

(b) The Company reserves the right to verify the identity of the Customer and the accuracy of the information provided and to require the Customer to sign an application in writing on forms provided by the Company. If a Customer is not of legal age, a Security Deposit may be required in order to obtain Services and, in addition, a person of legal age may be required to accept responsibility for the Services on that Customer's behalf.

(c) Contacts for Service are not transferable. Persons taking over premises, where Energy has been used previously, must make a new application for Service and pay the necessary Connection Fee per Article 4.3 and Security Deposit per Article 4.6.

4.2 Conditions of Service

Upon receipt of an application or contract for Service, the Company shall notify the applicant of any conditions which must be satisfied before the application or contract will be accepted and Service may be commenced.

4.3 Connection Fee

Whenever a connection is made, the Customer will pay a non-refundable Connection Fee as specified in Schedule D, which shall be included in the Customer's first billing or paid with the application for Service, (save and except that, where the Customer has paid a Construction Contribution for the Service, the Connection Fee shall be deemed to be included in the Construction Contribution).

4.4 Application of Rate Schedules

Whether or not a Customer has signed an application or contract for Service, these Terms and Conditions and the Rate Schedule applicable to the Service supplied by the Company shall apply. In addition to payments for Service, the Customer is required to pay the Company the amount of any tax or assessment levied by any tax authority on Service delivered to the Customers.

4.5 Extensions to Electric Heat Customers

On Isolated Systems, Service for electric space heating purposes may be supplied to Customers only with the prior written permission of the Company.

4.6 Security Deposit

(a) Security Deposit Requirements

The Company may require payment of a Security Deposit by an applicant or Customer under the following circumstances:

(i) the applicant has not established a Satisfactory Credit Rating with the Company;

(ii) the Customer's Service has been disconnected or restricted by a Current-Limiting Device; or

(iii) the Customer has not paid all past bills for Service.

If a Security Deposit is required and not been provided prior to connection, it will be added to the bill for Service and due in full on the due date identified on the bill.

(b) Amount of Security Deposits

The amount to be deposited with the Company shall be determined by the Company at the time of the Service application and shall be based on an estimate of the total amount billed over a period of three months in which Energy consumption by the Customer is expected to be the highest. The Security Deposit required may be adjusted accordingly based on the Customer's actual use of the Service or other information made available to the Company.

(c) Interest on Security Deposits

The Company will pay simple interest on the Security Deposit from the date the deposit is paid, at the rate of interest specified from time to time in the Yukon Landlord and Tenant Act and such interest will be credited to the Customer's account annually on the first bill following December 31 or when the deposit is refunded.

(d) Refunds of Security Deposit

A Security Deposit may be refunded or credited to the Customer's account with interest by the Company when:

(i) the Customer's Service is disconnected, other than for default in payment of accounts, and the Customer has paid all amounts owing to the Company; or

(ii) the Customer has established a Satisfactory Credit Rating.

(e) Use of Security Deposit

If a Customer fails to pay any amount billed, the Company may apply all or any portion of that Customer's Security Deposit to the unpaid amount. The Customer will then be required to fully restore the Security Deposit before Service is reconnected or continued.

4.7 Delay in Taking Service - Other than Subdivision

Except in the case of a Customer who requests service to a subdivision if Service is not taken within 30 days of the In Service Date, the Company may begin billing the Customer for the minimum amount specified in the appropriate rate schedule or as specified in the contract between the Company and the Customer, whichever is greater.

4.8 Extension of Service

(a) Customer's Construction Contribution

If the Company's estimated costs of extending Facilities at the request of a Customer are less than the Maximum Company Investment specified in Schedule B for the type of Service requested, the Customer will not be required to make any Construction Contribution. In all other cases, an agreement for payment of the Construction Contribution must be made between the Customer and the Company before any work on the extension is commenced.

(b) Cost Sharing

If a new Customer shares a portion or all of the costs of an existing extension, the existing Customers may be entitled to Cost Sharing of the Construction Contribution based on the amount of extension shared.

Cost Sharing will be administered for a term, as per the following table, commencing December 31 of the year of construction of the original extension.

Original Customer Contribution	Cost Sharing Period
Less than $10,000	5 Years
Greater than or Equal to $10,000	10 Years

The Company will not administer refunds of less than $50.00.

Cost sharing will not be eligible for non metered, public services such as street lights, and heat tapes.

4.9 Underground Subdivision Extensions

Underground subdivision extensions shall be undertaken subject to the conditions set out in Schedule C.

4.10 Conversion from Overhead to Underground Service

When a Customer requests that existing Company Facilities be converted from overhead to underground, the Customer may be charged for all costs incurred by the Company in connection with the conversion, including the following:

(a) the actual cost of removing the existing Facilities, less the estimated value of the salvaged material, plus

(b) the actual cost of installing the new underground Facilities, less any available Company Investment as specified in Schedule B.

4.11 Temporary Service

Where the Company reasonably believes that a requested Service will be temporary, a Connection Fee as specified in Schedule D will be assessed and the Company may require the Customer requesting the Service to pay the Company's total estimated cost of installation and removal of Facilities necessary for the desired Service less the estimated value of the salvaged material.

The Company may require that such payment be made before the temporary Service is installed.

4.12 Mobile Homes

(a) Service shall normally be provided to mobile homes through separate Points of Service, based on the applicable residential rate.

(b) Service provided to common use areas (e.g., laundry facilities) in a mobile home park shall be separately metered and billed at the applicable general service rate.

(c) In mobile home parks or trailer courts where the Company reasonably believes homes are temporary, the Company may elect to provide Service only through the Point of Service billed to the mobile home park or trailer court.

4.13 Multiple Dwellings

Each individual unit within a Multiple Dwelling will be served as a separate Point of Service and billed individually on the applicable residential rate. The Company and a Customer may agree that one bill will be issued covering all individual units in a Multiple Dwelling and, in such case, the applicable general service (non-residential) rate will apply to the Service.

4.14 Relocation of Company Facilities

The Company may require a Customer to pay all reasonable costs incurred by the Company in relocating any Company Facility at the Customer's request and may require payment of the estimated cost of the relocation in advance.

4.15 Reconnection

When the circumstances resulting in discontinuance of a Customer's Service or restriction of Service through the installation of a Current Limiting Device have been rectified to the satisfaction of the Company, or when a Customer has requested a reconnection after having requested a previous disconnection, the Company shall reconnect and continue the provision of Service upon payment by that Customer of:

(a) any amount owing to the Company;
(b) a Reconnection Fee as specified in Schedule D; and
(c) the Security Deposit, if any, required under Article 4.6;

If Service is reconnected within 12 months of disconnection, with the exception of seasonal Service:

a) For Major Industrial and general Service customers with peak demands greater than 500kW the Customer shall pay the minimum monthly bill for each month of disconnection.
b) For all other customers, the Company may request that the Customer pay the minimum monthly bill for each month of disconnection.

The Company may add a Collection Fee as specified in Schedule D if a site visit is required to attempt collection of overdue accounts and Service is not disconnected or for delivery of a notice of pending disconnection.

This section does not apply when a Customer's Service was disconnected for safety reasons. (Refer to Article 11.2)

5. RIGHTS OF WAY AND ACCESS TO FACILITIES

5.1 Easements

At the request of the Company, the Customer shall grant, or cause to be granted, to the Company, without cost to the Company, such easements or rights-of-way over, upon or under the property owned or controlled by the Customer as the Company reasonably requires for the construction, installation, maintenance, repair and operation of the Facilities required for a Service Connection to the Customer and the performance of all other obligations required to be performed by the Company hereunder.

5.2 Right of Entry

The Company's employees, agents or other representatives shall have the right to enter a Customer's property at all reasonable times for the purpose of installing, maintaining, repairing, replacing, testing, monitoring, meter reading or removing the Company's Facilities and for any other purpose incidental to the provision of Service. The Customer shall provide the Company with reasonable access to the Company Facilities located on the Customer's property. The Company will endeavour to provide reasonable notice to the Customer when the Company requires entry to the Customer’s property for planned maintenance or repair to the Company’s Facilities.

5.3 Vegetation Management

The Customer shall permit the Company to manage vegetation on the property owned or controlled by the Customer. Access is required to maintain the proper clearances and reduce the risk of contact with the Company's overhead high and low voltage distribution equipment. The Company shall make reasonable efforts to notify the Customer before such work is performed.

Vegetation management in the vicinity of the high voltage distribution system (primary) is the responsibility of the Company. Vegetation will be maintained to established standards to reduce contact with the energized conductors or equipment.

Vegetation management in the vicinity of the low voltage (service drops or secondary) distribution on the Customer’s property is the responsibility of the Customer. Where the Company determines that vegetation management is required to maintain the integrity of the Company’s low voltage overhead distribution system, the Company may, at the Customer’s expense, perform the work that is the responsibility of the Customer as set out herein. With respect to the low voltage overhead distribution system only, the Company shall make reasonable efforts to notify the Customer that such work is required, and shall provide the Customer a reasonable opportunity to undertake the work required, before such work is performed by the Company.

5.4 Interference with Company's Facilities

Customers shall not install, or allow to be installed, temporary or permanent structures that could interfere with the proper and safe operation of the Company's Facilities or result in non-compliance with applicable statutes, regulations, standards or codes.

5.5 Customer Brushing

Customers requesting Service that requires the extension of Facilities to the Customer's property shall be responsible for brushing on the Customer's property in accordance with the Company's specifications. In addition, unobstructed access to each structure requiring Service must be provided.

6. METERS

6.1 Installation

(a) Provision and Ownership

The Company shall provide, install and seal all meters necessary for measuring the Energy and Demand supplied to a Customer, unless otherwise specifically provided in a contract with the Customer. Each meter shall remain the sole property of the Company.

If required, as determined in the Company's sole discretion, current and voltage transformers and metering test switches will be supplied to the Customer for installation by the Customer's qualified personnel or contractor. Current and voltage transformers shall be installed in accordance with the Company's specifications and all codes, legislation and reference to applicable metering standards.

(b) Responsibility of Customer

Each Customer shall provide and install a CSA-approved meter receptacle or other CSA-approved Facilities suitable to the Company for the installation of the Company's meter or metering equipment.

6.2 Location

The location of any meter shall be subject to the approval by the Company having regard to the type of Service being provided and so as to permit safe and convenient access to the meter by the Company. Where a meter is installed on a Customer owned pole, the pole shall be provided and maintained by the Customer as required by the Canadian Electric Code and any other applicable legislation.

Meter sockets for self-contained meters shall be mounted on the exterior of a building at an accessible location acceptable to the Company. The centerline of the meter socket must be 1.5 to 1.8 meters above the finished grade or permanent platform of the Customer's Facility and in an appropriately lighted area.

Metering instrument transformer enclosures shall contain only the Company's metering auxiliary equipment and shall not be used as a raceway, splitter box or cabinet for any other purpose.

6.3 Meter Tests and Adjustments

(a) The Company may inspect and test a meter at any reasonable time. At the request of a Customer, and upon payment of a Meter Accuracy Test Handling Fee as specified in Schedule D, the Company shall arrange for a meter to be tested by an official designated for that purpose by Industry Canada or such other federal government agency as may, from time to time, be designated for that purpose.

(b) If a test determines that the meter is not accurate within the limits set by government standards, the Customer's bill will be adjusted back to the time that the error can reasonably be determined to have commenced. Where the commencement of the error cannot reasonably be determined, it shall be deemed to have commenced three months before the test or on the date of the meter installation, whichever occurred later.

(c) In the event that an adjustment is required, the Meter Accuracy Test Handling Fee shall be refunded.

6.4 Access to Meters

(a) The Company may, at any reasonable time, read, inspect, remove and test a meter installed on property owned or controlled by the Customer.

(b) Where the Customer's Service address or location is generally locked during normal business hours, the Customer shall provide the Company with a key to permit access to the meter.

(c) If the Company provides notice to a Customer that reasonable access to metering equipment is not being provided, the Customer must take immediate action to remedy the situation. If the Customer fails to remedy the situation to the Company's satisfaction within a reasonable time:

(i) the Company may, at its sole discretion, estimate consumption until the situation has been remedied and the Customer shall be billed on the basis of the Company's estimate;

(ii) the Company may remedy the situation on behalf of the Customer and apply the costs to the Customer's next regular bill;

(iii) the Company may do both i) and ii); or

(iv) the Company may discontinue Service in accordance with Section 11 of these Terms and Conditions of Service.

7. METER READING AND BILLING

7.1 Reading and Estimates

Unless otherwise specifically provided in a contract with a Customer, meters shall be read monthly or bi-monthly or at such other intervals as are practical in the circumstances. Customers' bills will be based on meter readings made by the Company or on estimates for those billing periods when the meter is not read. Whenever a bill is based on an estimate, an adjustment to reflect actual Energy consumption and Demand (if applicable) used will be made when the meter is next read.

7.2 Calculation of Bills

(a) The amount of any initial and final charges will be prorated, based upon the ratio of the number of days that Service was provided to a Customer in the billing period to the total number of days in the billing period.

(b) The Company may elect not to charge a Customer for the billing period if, during that period, Demand was five kilowatts or less, Service was provided for five days or less and Energy consumption was five kilowatt hours or less.

(c) For all new accounts, the Company may add the charges for Service provided during the initial period to the bill for the following billing period.

(d) The Company may elect to change a Customer’s meter reading schedule.

(e) Where a meter reading schedule is changed, any charges during the transition period between the old and new meter reading schedule, may be prorated based upon the ratio of the number of days that Service was provided to a Customer in the billing period to the total number of days in the billing period.

7.3 Payment

(a) The amount billed is due and owing when the bill is rendered and payable by the date indicated on the bill.

(b) Bills shall be deemed rendered and other notices duly given when delivered to the Customer at the mailing address provided by the Customer. Failure to receive a bill does not entitle a Customer to any delay in payment or release a Customer from the obligation to pay the amount owing.

(c) Payment of a bill for Service may be requested by the Company from any or all of the Customers, on a joint and several basis, even if the Customer no longer resides in the same premises when payment is due.

7.4 Late Payment Charge

The Company may add a Late Payment Charge as specified in Schedule D on any overdue amount. A Collection Fee as specified in Schedule D will be charged if a personal visit is required to collect an overdue amount.

7.5 Dishonoured Payments

The Company may add a Dishonoured Payments Fee as specified in Schedule D to a Customer's bill in respect of any cheque, or other form of payment tendered by the Customer as payment of a bill, returned by the Customer's bank for any reason.

Following the receipt of two (2) dishonoured payments from the Customer, the Company may notify the Customer that only cash, a money order or certified cheque will be accepted for payment.

7.6 Outstanding Charges

The Company may add to the Customer's bill any outstanding charges due and owing to the Company (e.g. construction contribution, account receivable charges, former overdue accounts etc.).

7.7 Totalized Metering

When Service is provided through multiple Points of Service to a Customer's plant site consisting of centralized processing facilities or product transportation facilities located on lands leased or owned by the Customer, where such multiple Points of Service are located within a radius of half a mile of each other, the Customer and Company may agree that the Demand and Energy at each Point of Service be totalized and only one bill issued for each billing period. The Customer shall pay the incremental metering cost associated with totalized metering.

7.8 Combined Service

A residential Customer shall notify the Company when the Customer receives Service at their premises for the purposes of operating a business or commercial undertaking. The applicable general service rate may be applied in those cases in which Service for both residential and non-residential purposes is received by a Customer through a single meter.

7.9 Consolidated Billing

The Company will issue a separate bill for each Point of Service. However, the Customer and Company may agree that the Company will issue one bill totaling charges for Service delivered at more than one Point of Service.

7.10 Unauthorized Use

If, under any circumstances, a person prevents a meter from accurately recording the total Demand or Energy supplied, the Company may disconnect the Service, or take other appropriate actions.

The Company may then estimate the Demand and amount of Energy supplied but not registered, at the Point of Service. The Customer shall pay the cost of the estimated Demand and Energy consumption plus all costs related to the investigation and resolution of the diversion including repairs of damage or reconstruction of Facilities.

7.11 Billing Error

The Customer must provide written notice to the Company in order to dispute any or all amounts owing on a bill. In the event the Customer disputes an amount owing, the Customer shall nonetheless pay such disputed amount. Following resolution of any such dispute, the Company will return any amount found owing to the Customer forthwith.

8. SERVICE CHANGES

8.1 Notice by Customer

A Customer shall give to the Company reasonable prior written notice of any change in Service requirements, including any material change in Connected Load, to enable the Company to determine whether or not it can supply such revised Service without changes to its Facilities. The Customer shall not change its Service requirements without the Company's written permission.

8.2 Responsibility for Damage

The Customer shall be responsible for and shall pay for all damage caused to the Company's Facilities as the result of the Customer changing the Connected Load without the Company's permission.

8.3 Changes to Company Facilities

If the Company must modify its Facilities to accommodate a Customer Load or Service change, the Customer shall pay for all costs in connection with such modification including the following costs:

(a) the actual cost of removing the existing Facilities, less the estimated salvage value, less

(b) any applicable adjustment required to the Company Investment as specified in Schedule B.

9. COMPANY RESPONSIBILITY AND LIABILITY

9.1 Continuous Supply

The Company shall make all reasonable efforts to maintain a continuous supply of Energy to its Customers, but the Company cannot guarantee an uninterrupted supply of Energy.

9.2 Interruption

Without liability of any kind to the Company, the Company shall have the right to disconnect or otherwise curtail, interrupt or reduce service to Customers:

(a) whenever the Company reasonably determines that the Service must be interrupted, including to facilitate construction, installation, maintenance, repairs, replacement or inspection of any of the Company's Facilities, or to permit the connection or disconnection of other Customers;

(b) to maintain the safety and reliability of the Company's Facilities; or

(c) due to any other reason related to dangerous or hazardous circumstances including emergencies, forced outages, potential overloading of the Company's Facilities or Force Majeure.

9.3 Reasonable Efforts

The Company shall endeavor to give reasonable notice to Customers who will have Service interrupted and will endeavor to ensure that such interruptions are as short and infrequent as circumstances permit.

9.4 Company Liability

For the purpose of this clause, "direct physical loss, injury or damage" excludes loss of revenue, loss of profits, loss of earnings, loss of production, loss of contract, cost of purchased or replacement capacity and energy, cost of capital, and loss of use of any facilities or property, or any other similar damage or loss, arising out of or in any way connected with the failure, defect, fluctuation, reduction or interruption in the provision of Service by the Company to its Customers.

Except as described below in this clause, the Company shall not be liable for any loss, injury, damage, expense, charge, cost or liability of any kind, whether of direct, indirect, special or consequential nature, arising out of or in any way connected with the provision of Service by the Company to its Customers including any failure, defect, fluctuation, reduction or interruption in the provision of Service by the Company to its Customers.

The Company shall be liable for direct physical loss, injury or damage to a Customer or a Customer's property, resulting from the negligent acts or omissions of the Company, its employees or agents.

9.5 Force Majeure

Should the Company be unable to provide a continuous supply of Energy to a Customer because of an event of Force Majeure, the Company's responsibilities, so far as they are affected by the Force Majeure, shall be relieved and suspended during the duration of such circumstances and the Company shall not be liable for any failure to perform any term of these Terms and Conditions to the extent that and when such failure is due to, or is a consequence of, an event of Force Majeure. Where practical, the Company shall give notice to the affected Customers of such Force Majeure.

10. CUSTOMER RESPONSIBILITY AND LIABILITY

10.1 Provide Permit

The Customer shall be responsible for obtaining all permits, certificates, licenses, inspections, reports, and other authorizations necessary for the installation and operation of the Service Connection. The Company shall not be required to commence or continue installation or operation of a Service Connection unless and until the Customer has complied with the requirements of all permits, certificates, licenses, inspections, reports and other authorizations, and all right-of-way agreements, and all Company requirements applicable to the installation and operation of the Service Connection.

10.2 Customer Responsibility

The Customer shall be solely responsible for the use, installation, condition of all Facilities on the Customer's side of the Point of Service, except Facilities owned by the Company. The Customer shall be responsible for and shall pay for any damage to the Company's Facilities located on the Customer's premises which is caused by the negligent acts or omissions or willful misconduct of the Customer or of anyone permitted by the Customer to be on the Customer's premises.

10.3 Customer Liability

(a) The Customer assumes full responsibility for the proper use of Facilities and for the condition, suitability and safety of any and all wires, cables, devices or equipment energized on the Customer's premises or on premises owned or controlled by the Customer that are not the Customer's property.

(b) Where a Customer uses its Service Connection in a manner that causes interference with the operation of the Company's Facilities or with any Customer's use of a Service Connection, such as abnormal voltage levels, frequency levels and harmonic levels, at the Company's request, and at the Customer's own expense, the Customer shall take whatever action is required to correct the interference or disturbance.

(c) The Customer shall indemnify and save harmless the Company from and against any claim or demand for injury to persons or damage to property (including loss of use thereof and of any other property affected by the damage to property) arising out of or in any way connected with the use of the service so long as such injury or damage is not caused by the negligent acts or omissions or willful misconduct of the Company, its employees and agents.

(d) The Customer releases the Company and its agents, directors, officers, employees, independent contractors, consultants, representatives, successors and assignees from any and all claims and liabilities whatsoever relating to or arising as a result of the Customer, or its agents, directors, officers, employees, independent contractors, consultants, representatives, successors and assignees carrying out any acts required by or related to these Terms and Conditions for the provision of Service, maintenance of Service, or any other act whatsoever arising out of or in any way connected with the existence or use of the Service so long as such injury or damage is not caused by the negligent acts or omissions or willful misconduct of the Company, its employees or agents.

10.4 Protective Devices

The Customer shall be responsible for determining whether any devices are required to protect the Customer's Facilities from damage that may result from the provision of Service by the Company. The Customer shall provide and install any such devices.

10.5 Service Calls

The Company may require a Customer to pay the actual costs of a Customer-requested service call if the source of the problem is the Customer's Facilities.

11. TERMINATION OF SERVICE

11.1 Termination by Customer

Except where otherwise provided in a written agreement between the Company and a Customer, a Customer may, at any time, give the Company reasonable notice to terminate Service. Upon receipt of such notice, the Company shall read the Customer's meter within a reasonable time, and, shall use its best efforts to read the Customer's meter at the time requested by the Customer. A Customer shall pay for all Service provided to the time of such reading.

11.2 Company Termination for Safety Reasons

The Company may, without notice, terminate a Customer's Service where, in the Company's opinion:

(a) the Customer has permitted the wiring of their Facilities to become hazardous;

(b) the wiring of the Customer's Facilities fails to comply with applicable law; or

(c) the Customer has caused any other safety hazards, including, but not limited to, using their Service in such a way that causes damage to the Company's Facilities or interferes with or disturbs Service to any other Customer.

The Company will reconnect the Service when the safety problem is resolved and when the Customer has provided, or paid the Company's costs of providing, such devices or equipment as may be necessary to resolve such safety problem and to prevent such damage, interference or disturbance. The Company may assess a Reconnection Fee, as specified in Schedule D.

11.3 Company Termination Other Than For Safety

The Company, or anyone acting under its authority, may, upon giving at least 48 hours' notice to the Customer, terminate the Customer's Service or install a Current-Limiting Device to restrict the Service to such Customer if the Customer:

(a) fails to meet its obligation under these Terms and Conditions, the terms of a contract for Service, or of the Company’s Rate Schedules;

(b) uses their Service Connection in such a way that causes interference with operation of the Company’s Facilities or any other Customer’s use of a Service Connection such as abnormal voltage levels, frequency levels and harmonic levels.

(c) tampers with any Company Facilities;

(d) neglects or refuses to pay the amount billed for Service due and owing to the Company by the date indicated on the bill for Service;

(e) changes Service requirements without the permission of the Company; or

(f) makes use of the Service for illegal purposes or in circumstances where the Company has evidence of Energy theft, or fraud by the Customer.

11.4 Removal of Facilities

Upon discontinuance of Service for whatsoever reason, the Company shall be entitled to remove any of its Facilities located upon the property of the Customer and to enter upon the Customer's property for that purpose.

SCHEDULE A: STANDARD SUPPLY SPECIFICATIONS

The Company's standard supply specifications, which are in accordance with Canadian Standards Association standard CAN-C235-83, are as follows:

(a) Residential:

240/120 V	- single phase, three wire - secondary conductors are supplied by the Company - overhead or, in designated areas, underground conductors are supplied by the Company

(b) General Service:

240/120 V	- single phase, three wire - overhead secondary conductors are supplied by the Company - underground secondary conductors are supplied by the customer
208 Y/120 V	- three phase, four wire - overhead secondary conductors are supplied by the Company - underground secondary conductors are supplied by the customer
480 Y/277 V	- three phase, four wire - overhead secondary conductors are supplied by the Company for loads 15 KVA to 300 KVA - overhead secondary conductors are supplied by the customer for loads 300 KVA to 1,500 KVA
600 Y/347 V	- three phase, four wire - underground secondary conductors are supplied by the customer for loads 150 KVA to 2,500 KVA; and
4160 Y/2400 Y	- three phase, four wire, 2,000 KVA to 10,000 KVA - overhead secondary conductors are supplied by the customer

SCHEDULE B: MAXIMUM COMPANY INVESTMENT

The Maximum Company Investment Levels set out in this Schedule are effective January 1, 2011.

1. Subject to the provisions of paragraph 2 of this Schedule B, the maximum Capital Cost which the Company will incur to extend Service to a Point of Service (herein referred to as the "Maximum Company Investment") shall be determined as follows. Under no circumstances would the Maximum Company Investment exceed the Customer extension cost:

(a) Residential Service:

$1,500 per single family dwelling; and
$ 725 per Multiple Dwelling unit

(b) General Service:

$690 per kW, which shall not be less than five kilowatts, provided that if the estimated service life is less than 25 years or seasonal, then the Maximum Company Investment shall be determined in the manner described in paragraph 2;

At the end of one year of Service the Company will re-assess whether the Customer's estimates of their Demand were accurate and, if the loads are significantly different than originally estimated, will collect from the Customer (or refund) any contributions, that are required based on the Maximum Company Investment rules in place when the contribution was originally paid.

c) Municipal Street Lighting:

$1,240 per light.

2. The Maximum Company Investment in any extension of service, whether or not specified in paragraph 1, the Load characteristic and service life of which are expected to vary materially from the average for that type of Service, shall be determined based on an analysis of the load characteristics and service life, as a pro-ration of the full Maximum Company Investment for that class of customer.

3. The maximum cost which the Corporation will incur to extend Service to a Point of Delivery shall be determined for Industrial Service in the manner specified in an agreement with the Industrial Customer and subject to approval by the Board.

SCHEDULE C: CONDITIONS FOR UNDERGROUND SUBDIVISIONS

"**Developer**" is defined as the person or party who has requested the underground service. The Company shall extend service by underground conductor lines upon and subject to the following terms and conditions

(a) At the time of the request for underground Service no Service available in the area to be served by such extension, and not less than 25 single family dwellings (or such lesser number as may be agreed to by the Company) will be connected to such extension (the "underground service area"), each of which is situated upon said subdivision;

(b) All permanent Service in the underground service area shall be provided exclusively through underground conductor lines;

(c) The Developer shall provide, without cost to the Company, such rights-of-way, easements, utility corridors and transformer locations as the Company may require for the installation, operation and maintenance of such extension, which the Developer shall keep free and clear of any buildings, structures, fences, pavement, trees or any other obstructions which may hinder the Company in installing, maintaining or removing its Facilities;

(d) The Company shall not be obligated to install such extension until it is reasonably satisfied that the extension will not thereafter be damaged or interfered with, and, in any event, any costs incurred by the Company in relation to the relocation, reinstallation or as a result of damage to such extension shall be paid by the Developer;

(e) Service, for purposes other than residential use and street lighting, may be provided from such extension only with the consent of the Company;

(f) In relation to the standard underground Service, the Developer shall provide a meter socket and service conductor protection from sixty centimeters below grade level to the line side of the meter socket and will ensure the installation of a service having a 200 ampere capacity. Non-standard Services will be subject to prior written approval by the utility;

(g) The Developer shall provide to the Company a certified copy of the registered plan of subdivision and final construction plans showing the location and elevation of sidewalks, curbs and gutters, driveways (if known) and underground utilities together with such evidence as the Company may reasonably require to the effect that all rules and regulations applicable to the development have been or will be compiled with by the Developer;

(h) Survey stakes indicating grades and property lines shall be installed and maintained by the Developer;

(i) The surface of the ground for a distance of not less than one point five (1.5) meters on each side of the alignments for the underground conductor lines shall be graded by the developer to within eight (8) centimeters of a final grade;

(j) Unless otherwise agreed to by the Company, the Developer shall provide a survey for the location of transformers, street light bases and cable routing, as required;

(k) Sidewalks, curbs and gutters may be constructed by the Developer but no other permanent improvements shall be made until approved by the Company.

(l) Costs related to the installation of distribution system infrastructure shall be the responsibility of the Developer; and

(m) The Company investment will be applied toward the individual Customer Service connection in accordance with Schedule B.

In addition, the Service shall be subject to such other conditions as may be specified by the Company from time to time.

SCHEDULE D : FEES AND SERVICE CHARGE SUMMARY

CONNECTION, and RECONNECTION FEES

Connection Fee (4.3, 4.11):	
During normal business hours:	$50.00
Outside of normal business hours:	Company's actual cost (min. $50.00)
Reconnection Fee (4.15, 11.2)	
During normal business hours:	$60.00
Outside of normal business hours:	Company's actual cost (min. $60.00)

LATE PAYMENT AND DISCONNECTION

Collection Fee (4.15, 7.4)	$30.00 (personal visit)
Late Payment Charge (7.4):	1.5% per month (19.56% per annum)
Dishonoured Payments Fee (7.5):	$25.00

METER DISPUTES

Meter Accuracy Test Handling Fee (6.3)	
Self Contained Meter	$100.00
Instrument Meter	$200.00